teri The Energy and Resources Institute

Darbari Seth Block
I H C Complex
Lodhi Road
New Delhi – 110 003

Tel. 2468 2100 or 2468 2111
E-mail mailbox@teri.res.in
Fax 2468 2144 or 2468 2145
India +91 • Delhi (0) 11

Web www.teriin.org

Regional centres within India

North-Eastern Regional Centre
Guwahati
Tel. (361) 234 5395 or 234 4363
E-mail terine@sify.com
Fax (361) 234 5395

Eastern Regional Centre
Kolkata
Tel. (33) 2283 0550 or 2283 0551
E-mail terierc@teri.res.in
Fax (33) 2283 0551

Southern Regional Centre

Shantanu Ganguly
Associate Editor (Mycorrhiza Newsletter)

Ext.2722
shantanu@teri.res.in

20 July, 2004

Dr M.P.Babita
Downy Mildew Research Laboratory
Department of Applied Botany and Biotechnology
University of Mysore
Manasagangotri. – 570 006
Karnataka, India.

Dear Dr Babita,

Lecture notes on "Thermal design and testing of steam generation "

Prepared for: Internal Training Programme
Industrial Energy Group, EET

Prepared by: Dr Y P Abbi
Senior Fellow

August 2002

Thermal design & testing of steam generators

Chapter Contents

1. Properties of steam
2. Fluid flow principles
3. Heat transfer principles
4. Fuels & combustion stoichiometry
5. Design considerations for steam generators
6. Fuel firing system for solid fuel
7. Testing efficiency of fired boilers
8. Heat recovery steam generators

Chapter 1

Properties of steam

Properties of steam

Introduction

- Since late 17th century, few technologies that the ingenuity of man have produced, have done so much to advance mankind as the *"Safe & dependable generation of steam"*.
- Basic principles
  - generate heat; transfer the heat to water and produce steam at required temperature & pressure
  - Sources of heat
    - Fossil fuels (coal, oil, NG)
    - Biomass, bagasse etc
    - Waste heat/exhaust heat
    - Solar thermal
    - Uranium (nuclear fuel)

Contd.

- Uses of steam
  - drives turbines for generators, large pumps, compressors
  - heating & cooling processes for industry
    - pulp and paper
    - chemicals
    - food products
    - etc
  - as a reactant for
    - fuel gasification
    - shift reaction
- Types of boilers
  - Fire tube or flue tube (since 1870) (for low capacity & low pressure steam)
  - Water tube (since 1881) (for high capacity & high pressure steam)
  - Municipal waste incinerators
  - Chemical recovery (for paper industry)
  - Waste heat recovery/heat recovery
- Capacity up to 4435 t/h at 543 °C and 265 bar (1300 MW power

Properties of steam

- Saturated steam condition- At which the liquid & vapour phase of water co-exist at thermodynamic equilibrium
- Superheated steam condition- When the steam is heated above the saturation temperature
- Sub-cooled or compressed water- When water is cooled below its saturation temperature.
- Quality or dryness fraction of steam (x)

$$x = \frac{M_s}{M_s + M_w}$$

where M_s = mass of steam

M_w = mass of water

- Properties of steam from ASME 1983 Steam Tables are internationally accepted

Table. Units of steam produced

Property	English	mks	SI
Specific volume (υ)	ft^3/lb	m^3/kg	m^3/kg
Enthalopy (H)	btu/lb	kCal/kg	kJ/kg
Entropy (S)	btu/lb (R)	kCal/kg (K)	kJ/kg (K)

Note: v, H & S for fluid (water or steam) are unique functions of temperature & pressure

Entropy

- Thermodynamic processes (Boiler, steam turbine, compressor, pump, nozzles etc) are governed by laws of conservation of mass and conservation of energy, called 1st law of thermodynamics. It states that total mass or energy (in any of its forms) can neither be created nor destroyed in a process.

  Conservation of mass

  m_1-m_2 = 0

  Conservation of energy

  E_2-E_1=Q-W

  E_2 & E_1 are energy out & in respectively (in a Process)

  m_2 & m_1 are mass out & in respectively (in a Process)

  Q is heat added to the Process

  W is work done by the Process

- Kelvin statement of 2nd Law of Thermodynamics:

  Heat can flow only from a hotter to colder body i.e. from higher temperature to lower temperature.

Contd.

- Based on 2nd Law of Thermodynamics, Clausius defined the intensity factor of temperature as entropy

$$S_2 - S_1 = \Delta S = \text{mass} \times \int_1^2 \frac{\delta q_{rev}}{T}$$

where ΔS = Change of entropy, (Btu/R) or (J/K)

q_{rev} = Reversible heat flow between thermodynamic equilibrium states 1&2 of the system, (Btu/lb) or (J/kg)

T = Absolute temperature, (R) or (K)

- Steam tables give specific entropy, S/unit mass

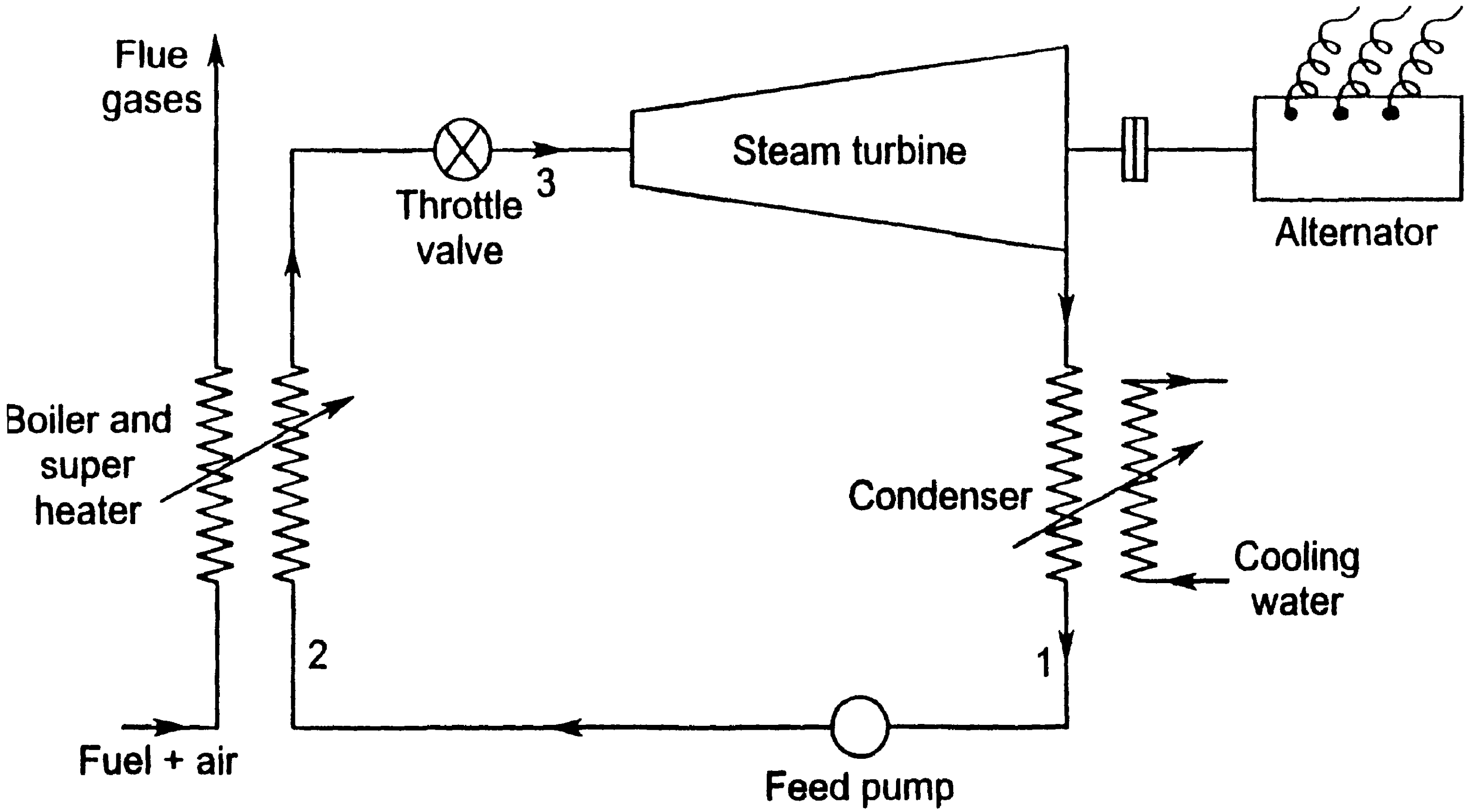
  i.e (kCal/kg (R)) or (kJ/kg (K))

- For a ‘steam turbine’ process

$$\delta(Wk) = Tds$$

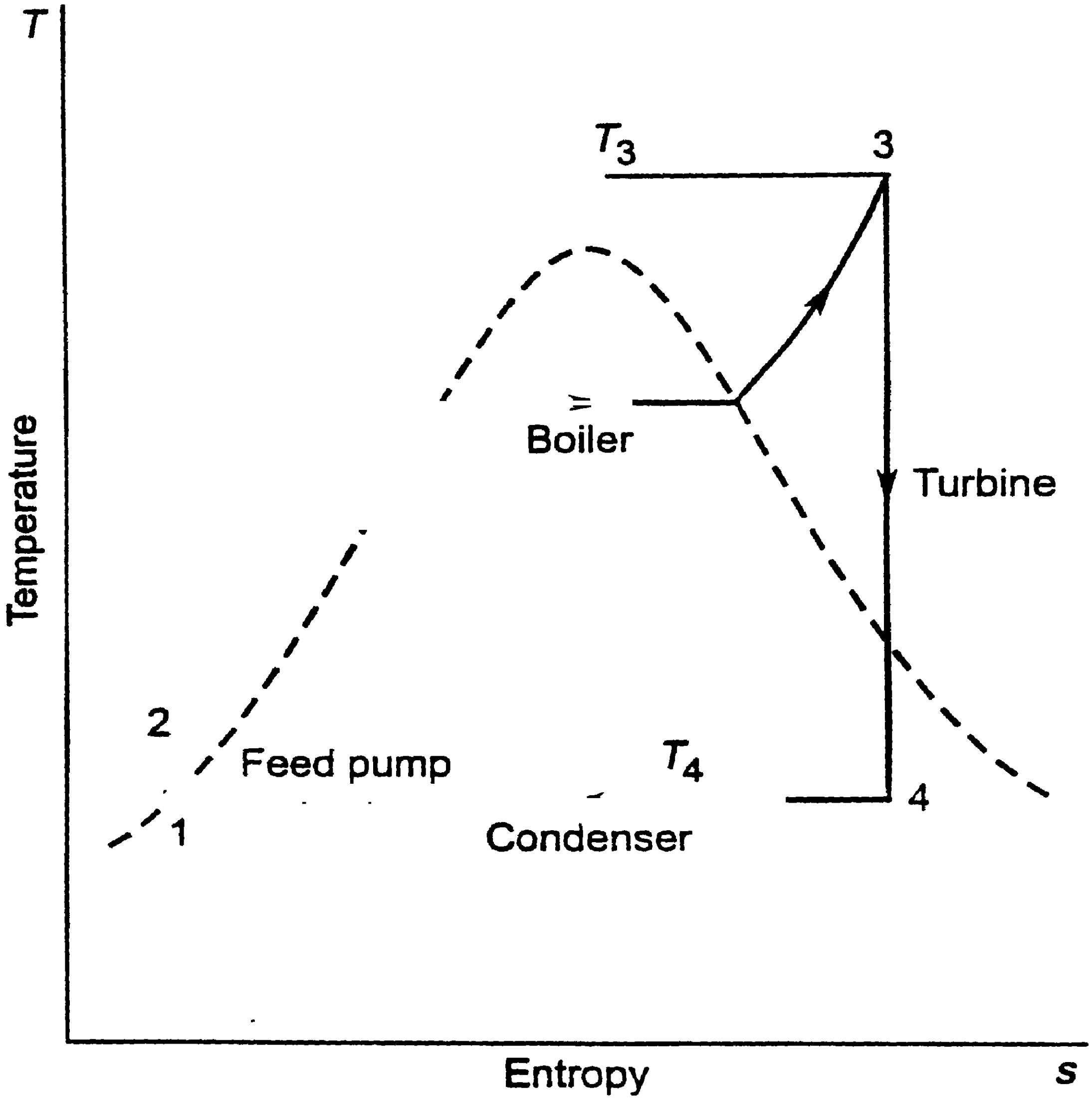
$$W_k = \int_1^2 T\,ds$$

where W_k = Work done per unit mass

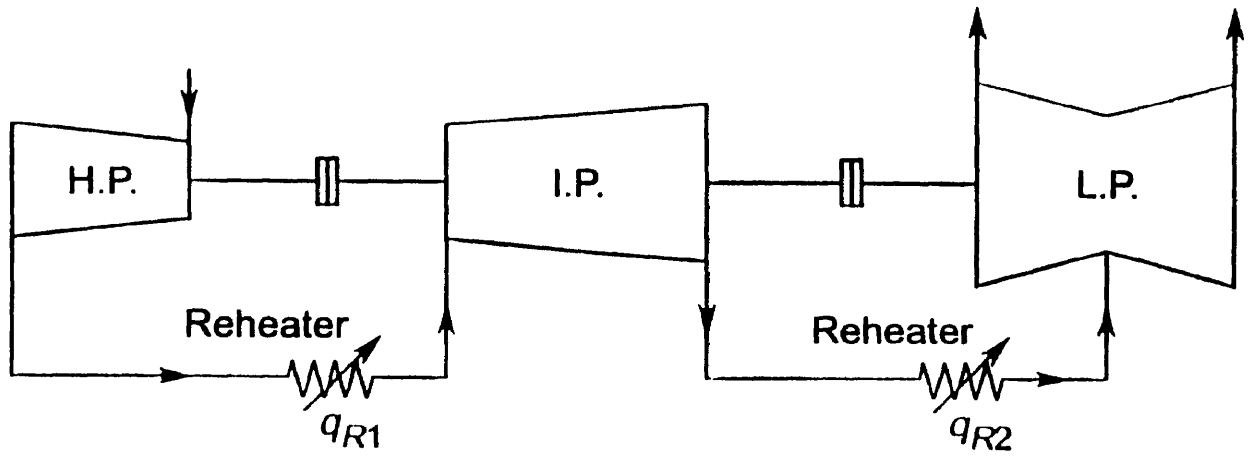


Layout of a steam turbine plant

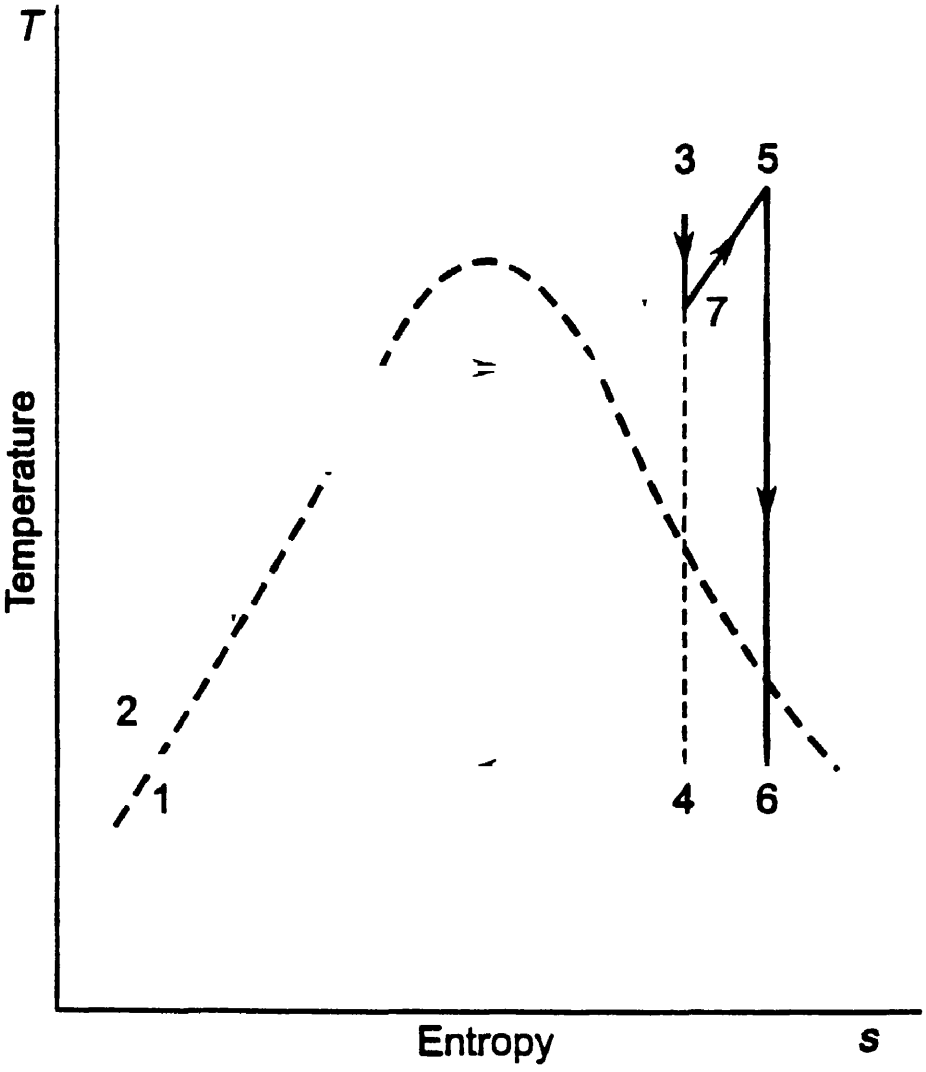
$$w_{\text{plant}} = w_T - w_P = Q_s - Q_r$$



T–s diagram of a Rankine cycle



Reheating of steam between H.P. and I.P. and L.P. cylinders



Rankine cycle with single reheat

Chapter 2

Fluid flow principles

Pressure loss from fluid friction in pipelines/ducts

The pressure drop of fluids flowing through closed circuits (pipes and ducts) is given by following formula:

$$\Delta P = f \frac{L}{D} \frac{\upsilon G^2}{2\,gc}$$

ΔP = fluid pressure drop, psi

f = friction factor, dimensionless (from figure)

L = Length, ft

D or De = equivalent dia, in

D & De are same for circular pipes

$$De = \frac{4 \times \text{flow area}}{\text{Wetted perimeter}}, \text{for non} - \text{circular duct}$$

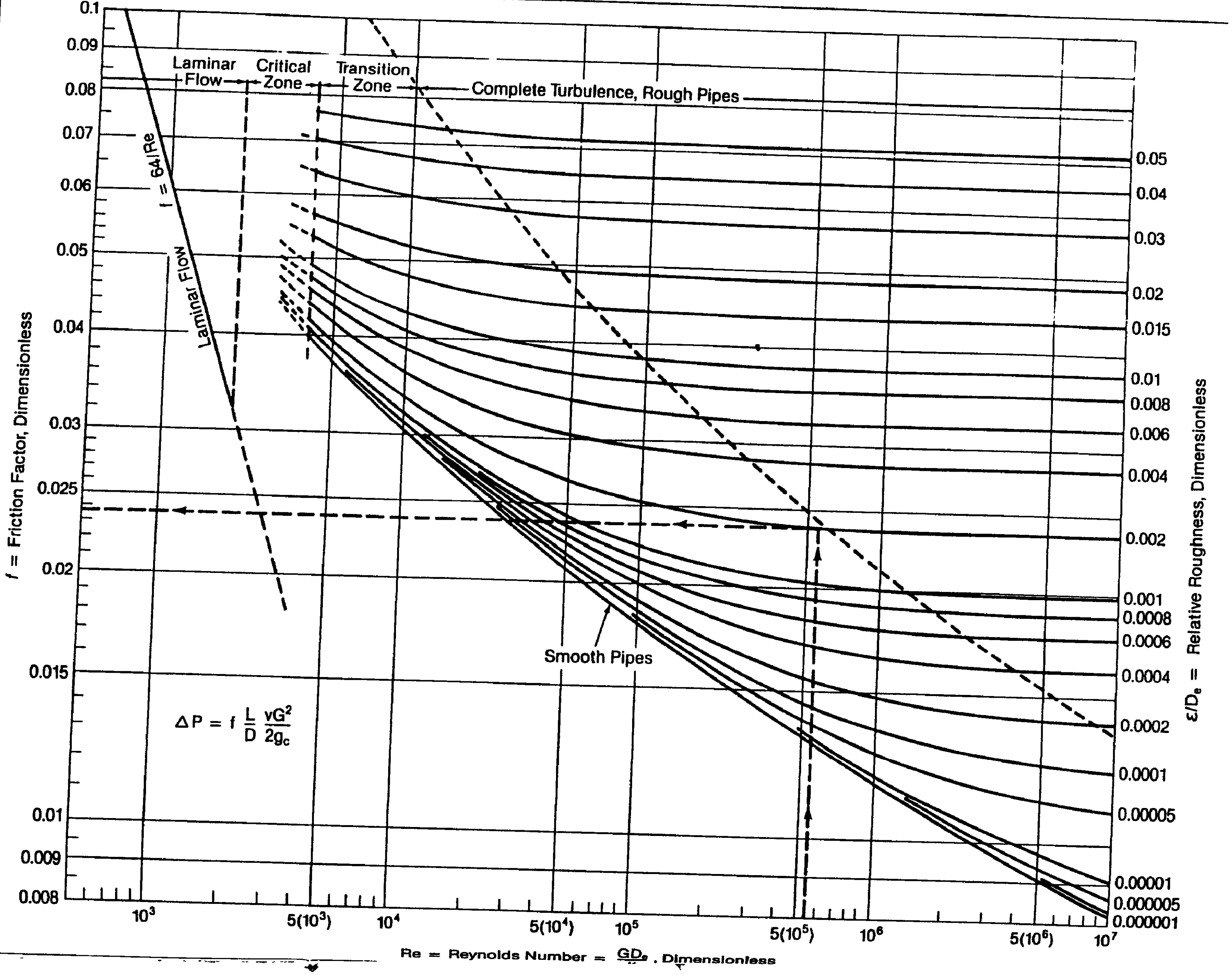
υ = specific volume of fluid, ft^3/lb

G = mass velocity of fluid, $lb/h\ ft^2$

The friction factor is plotted in the figure as a function of Reynolds number (Re),

$$Re = \frac{\rho V De}{\mu} \text{or} \frac{V De}{\upsilon\, kv} \text{or} \frac{G De}{\mu}$$

where ρ = density of fluid, lb/ft^3 (kg/m^3)


0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.025
0.02
0.015
0.01
0.009
0.008
f = Friction Factor, Dimensionless
Laminar Flow
Critical Zone
Transition Zone
Complete Turbulence, Rough Pipes
f = 64/Re
Laminar Flow
Smooth Pipes
$\Delta P = f \frac{L}{D} \frac{vG^2}{2g_c}$
0.05
0.04
0.03
0.02
0.015
0.01
0.008
0.006
0.004
0.002
0.001
0.0008
0.0006
0.0004
0.0002
0.0001
0.00005
0.00001
0.000005
0.000001
ε/D$_e$ = Relative Roughness, Dimensionless
10^3
$5(10^3)$
10^4
$5(10^4)$
10^5
$5(10^5)$
10^6
$5(10^6)$
10^7
Re = Reynolds Number = $\frac{GD_e}{\mu}$, Dimensionless

V_{kv} = kinematic viscosity = $\frac{\mu}{\rho}$, ft^2 (m^2/s)

μ = absolute viscosity of fluid, lb/ft h (kg/ms)

v = velocity of fluid, ft/h (m/s)

G = mass velocity of fluid, lb/h ft^2 (kg/m^2s)

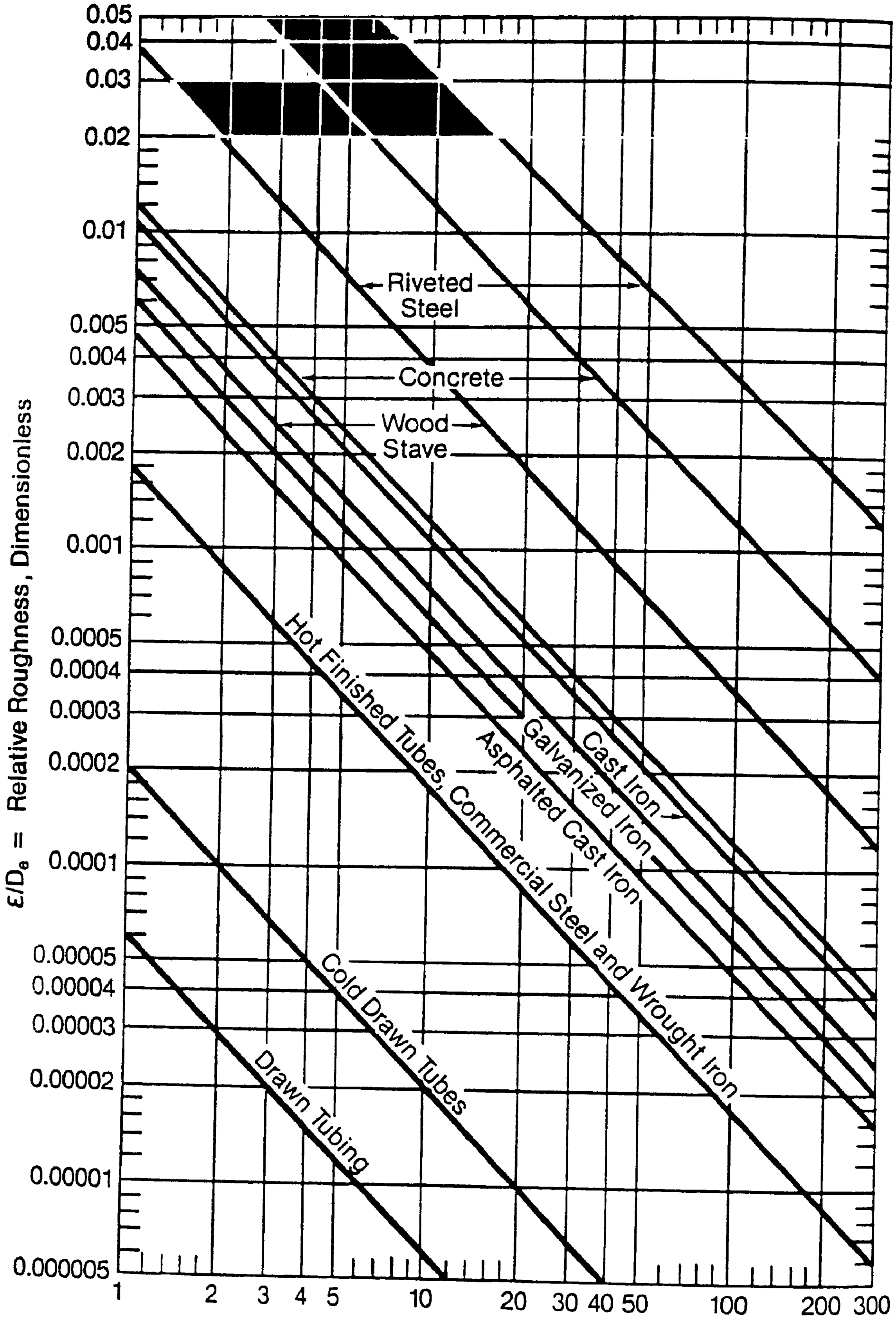
De= equivalent diameter of flow channel, ft (m)

- The flow is laminar (viscous) for Re less than 2000 and turbulent for Re above 4000. The Re between 2000 to 4000 is called critical zone.

  For laminar flow,

  F = 64/Re

- The relative roughness of the pipe/channel surface is defined as ϵ/De and can be found from text books or handbooks. Also properties of fluids are available in similar literature.
- Based on research work and design/operating experience, the optimum velocities in different section have been evolved. These are given in enclosed tables.



Relative roughness of various conduit surfaces. (SI conversion: mm = 25.4 × in.)

- The pressure loss due to valves, fittings and bends in a pipeline based on their equivalent lengths (determined experimentally, and supplied by the manufacturers), or in terms of equivalent number of velocity heads

$$\Delta P = N\upsilon \frac{\upsilon}{12}\left(\frac{G}{105}\right)^2$$

ΔP= pressure drop, psi

$N\upsilon$ = no of equivalent velocity heads, dimensionless

υ = specific volume, ft^3/lb

G = mass velocity, lb/ft^2h

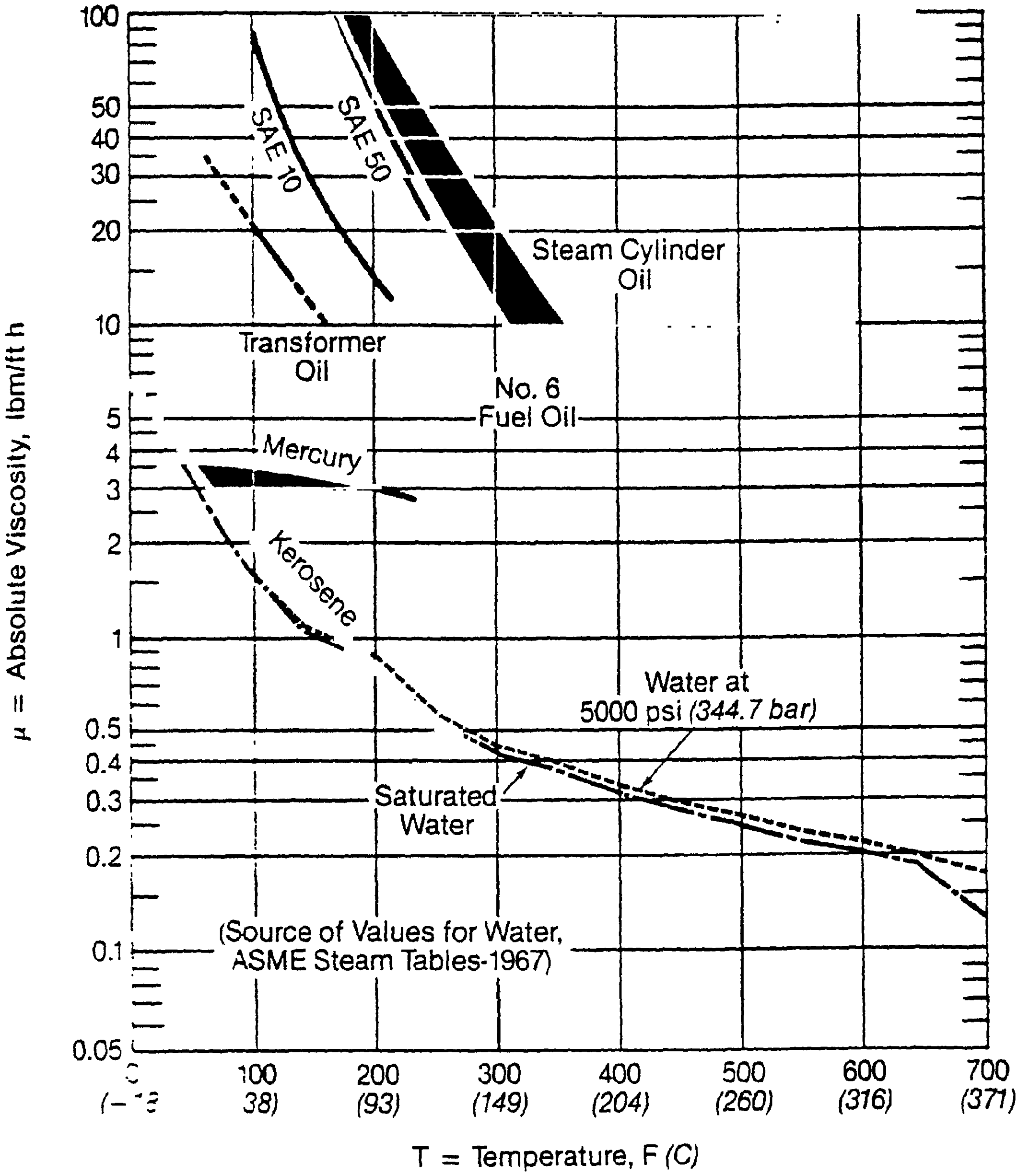
- $N\ \upsilon$ value for commercial fittings are given in the enclosed table
- Related Readings
  - Pressure loss due to contraction and enlargement in pipes
  - Flow through bends
  - Flow through coils
  - Flow through rectangular ducts
  - Flow over tube banks (bare tubes)
  - Flow over tube banks (finned tubes)
  - Flow through stacks and chimneys
  - Pressure drop in 2 phase (steam-winter) flow

Physical Properties of Gases at 14.7 psi (1.01 bar)**

			Instantaneous Specific Heat		
Gas	Temperature F	Density, lb/ft^3	c_p Btu/lb F	c_v Btu/lb F	k, c_p/c_v
Air	70	0.0749	0.241	0.172	1.40
	200	0.0601	0.242	0.173	1.40
	500	0.0413	0.248	0.180	1.38
	1000	0.0272	0.265	0.197	1.34
CO_2	70	0.1148	0.202	0.155	1.30
	200	0.0922	0.216	0.170	1.27
	500	0.0634	0.247	0.202	1.22
	1000	0.0417	0.280	0.235	1.19
H_2	70	0.0052	3.440	2.440	1.41
	200	0.0042	3.480	2.490	1.40
	500	0.0029	3.500	2.515	1.39
	1000	0.0019	3.540	2.560	1.38
Flue gas*	70	0.0776	0.253	0.187	1.35
	200	0.0623	0.255	0.189	1.35
	500	0.0429	0.265	0.199	1.33
	1000	0.0282	0.283	0.217	1.30
CH_4	70	0.0416	0.530	0.406	1.30
	200	0.0334	0.575	0.451	1.27
	500	0.0230	0.720	0.596	1.21
	1000	0.0151	0.960	0.836	1.15

* From coal; 120% total air; flue gas molecular weight 30.

** SI conversions: T, C = 5/9 (F-32); ρ, kg/m^3 = 16.02 × lbm/ft^3; c_p, kJ/kg K = 4.187 × Btu/lbm F.



Absolute viscosities of some common liquids (Pa s = 0.000413 × lbm/ft h).

Physical Properties of Liquids at 14.7 psi (1.01 bar)

Liquid	Temperature F (C)	Density, lb/ft^3 (Mg/m^3)	Specific Heat Btu/lb F (kJ/kg C)
Water	70 (21)	62.4 (1.000)	1.000 (4.19)
	212 (100)	59.9 (0.959)	1.000 (4.19)
Automotive oil	70 (21)		
SAE 10		55 to 57 (0.88 to 0.91)	0.435 (1.82)
SAE 50		57 to 59 (0.91 to 0.95)	0.425 (1.78)
Mercury	70 (21)	846 (13.6)	0.033 (0.138)
Fuel oil, #6	70 (21)	60 to 65 (0.96 to 1.04)	0.40 (1.67)
	180 (82)	60 to 65 (0.96 to 1.04)	0.46 (1.93)
Kerosene	70 (21)	50 to 51 (0.80 to 0.82)	0.47 (1.97)

Velocities Common in Steam Generating Systems

	Velocity	
Nature of Service	ft/min	m/s
Air:		
Air heater	1,000 to 5,000	5.1 to 25.4
Coal and air lines, pulverized coal	3,000 to 4,500	15.2 to 22.9
Compressed air lines	1,500 to 2,000	7.6 to 10.2
Forced draft air ducts	1,500 to 3,600	7.6 to 18.3
Forced draft air ducts, entrance to burners	1,500 to 2,000	7.6 to 10.2
Ventilating ducts	1,000 to 3,000	5.1 to 15.2
Crude oil lines [6 to 30 in. (152 to 762 mm)]	60 to 3,600	0.3 to 1.8
Flue gas		
Air heater	1,000 to 5,000	5.1 to 25.4
Boiler gas passes	3,000 to 6,000	15.2 to 30.5
Induced draft flues and breaching	2,000 to 3,500	10.2 to 17.8
Stacks and chimneys	2,000 to 5,000	10.2 to 25.4
Natural gas lines (large interstate)	1,000 to 1,500	5.1 to 7.6
Steam:		
Steam lines		
High pressure	8,000 to 12,000	40.6 to 61.0
Low pressure	12,000 to 15,000	61.0 to 76.2
Vacuum	20,000 to 40,000	101.6 to 203.2
Superheater tubes	2,000 to 5,000	10.2 to 25.4
Water:		
Boiler circulation	70 to 700	0.4 to 3.6
Economizer tubes	150 to 300	0.8 to 1.5
Pressurized water reactors		
Fuel assembly channels	400 to 1,300	2.0 to 6.6
Reactor coolant piping	2,400 to 3,600	12.2 to 18.3
Water lines, general	500 to 750	2.5 to 3.8

Relationship Between Various Units of Viscosity

Part A: Absolute (or Dynamic) Viscosity, μ

Pa s $\frac{N\,s}{m^2}=\frac{kg}{m\,s}$	Centipoise $\frac{0.01\,g}{cm\,s}$	$\frac{lbm}{ft\,s}$	$\frac{lbm}{ft\,h}$	$\frac{lbf\,s}{ft^2}$
1.0	1,000	672×10^{-3}	2420	20.9×10^{-3}
0.001	1.0	672×10^{-6}	2.42	20.9×10^{-6}
1.49	1488	1.0	3600	0.0311
413×10^{-6}	0.413	278×10^{-6}	1.0	8.6×10^{-6}
47.90	47,900	32.2	115,900	1.0

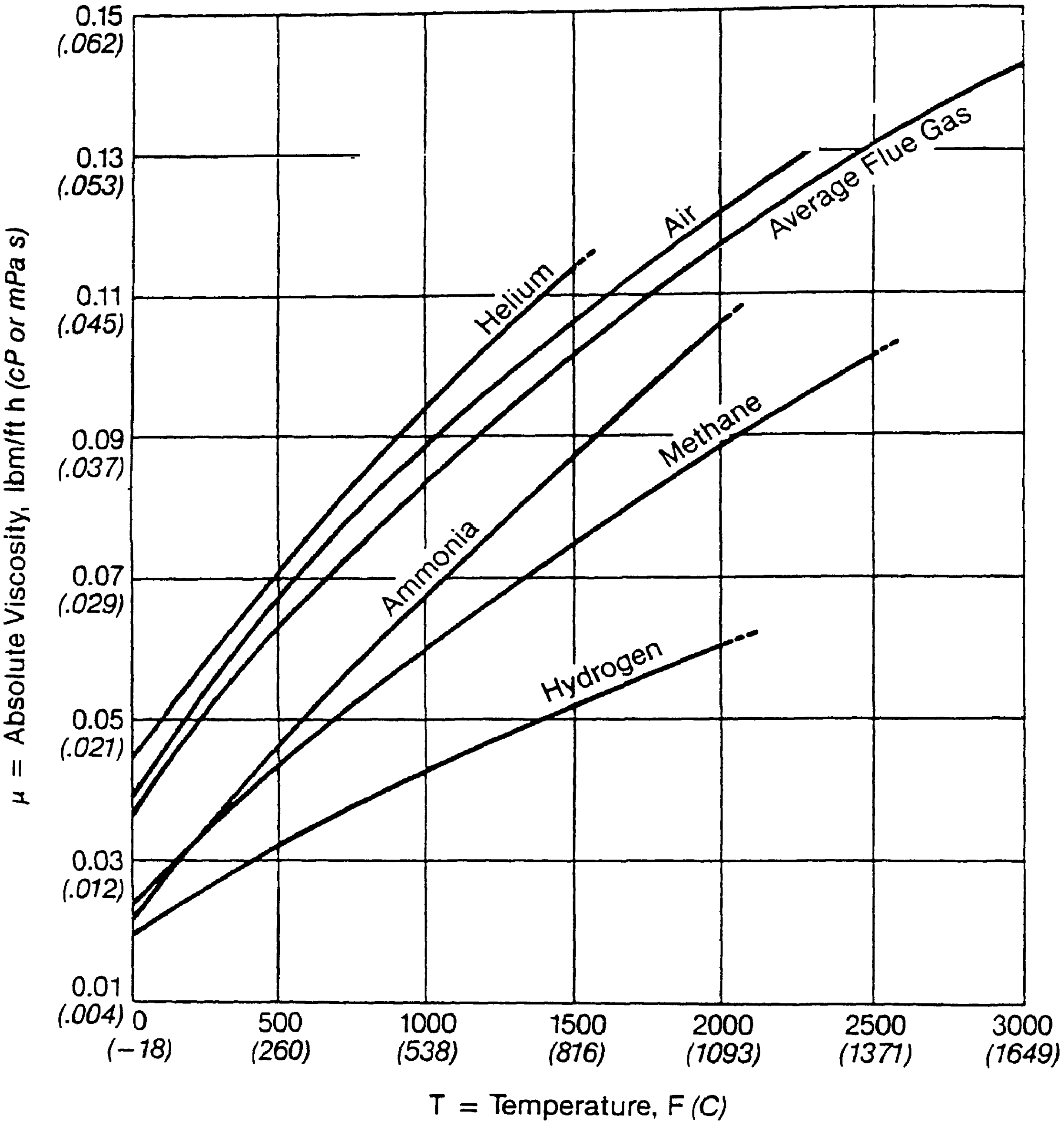
Part B: Kinematic Viscosity, $\upsilon = \mu/\rho$

$\frac{m^2}{s}$	Centistoke $\frac{0.01\,cm^2}{s}$	$\frac{ft^2}{s}$	$\frac{ft^2}{h}$
1.0	10^6	10.8	38,800
10^{-6}	1.0	10.8×10^{-6}	0.0389
92.9×10^{-3}	92,900	1.0	3,600
25.8×10^{-6}	25.8	278×10^{-6}	1.0

Resistance to Flow of Fluids Through Commercial Fittings*

Fitting	Loss in Velocity Heads
L-shaped, 90 deg (1.57 rad) standard sweep elbow	0.3 to 0.7
L-shaped, 90 deg (1.57 rad) long sweep elbow	0.2 to 0.5
T-shaped, flow through run	0.15 to 0.5
T-shaped, flow through 90 deg (1.57 rad) branch	0.6 to 1.6
Return bend, close	0.6 to 1.7
Gate valve, open	0.1 to 0.2
Check valve, open	2.0 to 10.0
Globe valve, open	5.0 to 16.0
Angle valve, 90 deg (1.57 rad) open	3.0 to 7.0
Boiler nonreturn valve, open	1.0 to 3.0

* See Fig. 9 for loss in velocity heads for flow of fluids through pipe bends.



Absolute viscosities of some common gases at atmospheric pressure.

Chapter 3

Heat transfer principles

Heat transfer

Modes of heat transfer

1 Conduction - from one part of body to another part or from one body to other in physical contact

2 Convection - from one point to another within a fluid by mixing of one part with another due to movement of the fluid. This movement can be free or natural, or can be forced through external mechanical force like fan, pump

3 Radiation - from one body to another by electromagnetic waves (which do not require a medium)

Conduction heat transfer

- For a flat plate, heat flow rate q is expressed as

$$q = \frac{K\,A\,(t_1 - t_2)}{l}$$

where q= rate of heat flow, k Cal/h

K thermal conductivity, kCal/h (m)(°C)

A=heating surface, m^2

(t_1-t_2)= temperature difference between the hot & cold end of plate, °C

l = thickness of the plate, m

- Metals - good conductors, high value of K
- Other materials - having low value of K, are used as insulators
- When more than one materials are in contact, then combined resistivity

$$\frac{1}{K} = \frac{l_1}{K_1} + \frac{l_2}{K_2} + - - - - -$$

Convection heat transfer

- Heat transfer between a fluid and sold surface is

$$q_c = hc\ A\ \Delta t$$

where q_c = rate of heat flow by convection, kCal/h

A = heat transfer surface, m^2

hc - convection heat transfer coefficient, kcal/h (m^2) (°C)

Δt = Temperature difference between fluid bulk temperature and the solid surface temperature, °C

- Free or natural convection

$$h_{fc} = C\ (\Delta t)^{\frac{1}{3}}$$

where h_{fc} = free heat transfer coefficient, kCal/h (m^2) (°C)

C = coeff characteristic of shape and position of surface

Δt = diff in temperature between surface and the fluid, °C

Applicable only for external surface of boiler

Forced convection

- Application for most of heat transfer inside the boiler
- Calculated through empirical correlation
- Based on experimental data, Colburn recommended that for low viscosity gases and liquids

$Nu = 0.023\ (Re)^{0.8}\ (Pr)^{0.33}$

where Nu = Nussult number (dimensionless)

$$= \frac{hc\ D}{K}$$

D is diameter of tube, m

K is conductivity of liquid, kCal/h (m^2)°C

Re = Reynolds number (dimensionless)

$$= \frac{DVP}{\mu}$$

V = fluid velocity, m/s; ρ = fluid density, kg/m^3

μ = absolute viscosity, kg/m(s)

Pr = Prandtl number (dimensionless)

$$= \frac{Cp\ \mu}{K}$$

Convection heat transfer applicable to boilers

- For heat transfer from combustion gases to tubular surfaces in the convection pass,

$$\mathrm{Nu} = 0.287(\mathrm{Re})^{0.61}(\mathrm{Pr})^{0.33}(\mathrm{Fa})$$

where Fa = Arrangement factor for tube bundle (refer figure attached)

Radiation heat transfer

- For every radiation falling on a surface,

$$\rho + T + \propto = 1$$

where ρ = fraction of radiation reflected (Reflectivity)

T = fraction of radiation transmitted (Transmitivity)

$\propto$ = fraction of radiation absorbed (absorbtivity)

- For a black body, $\propto = 1$. It means that it absorbs all the radiant energy incident upon it.
- Radiation emitted by a black body, q is

$$q = \sigma A(T^4)$$

σ = Stefan-Boltzman constant

A = Surface area of body

T= Absolute temperature of emitter

- For other than black bodies

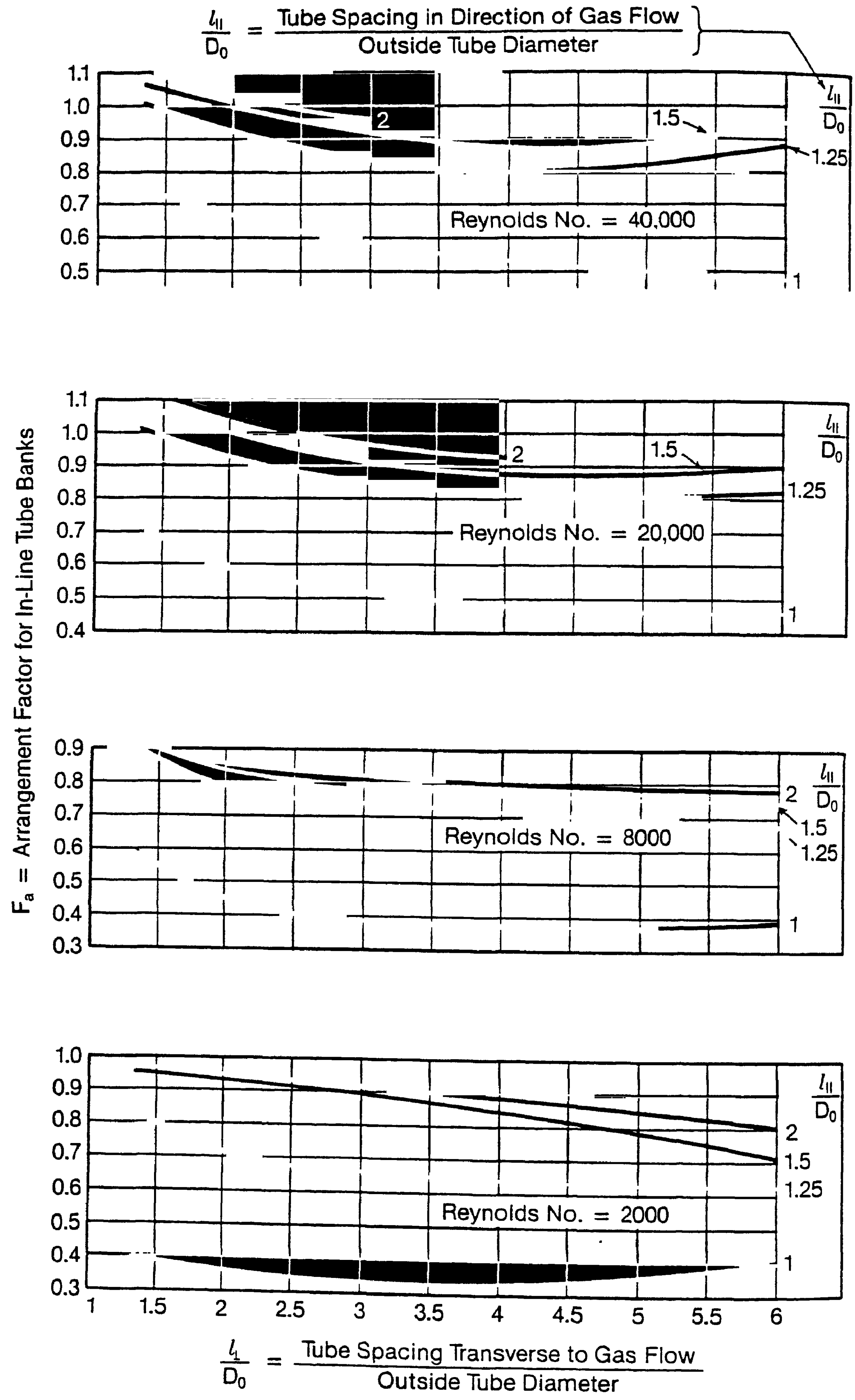
$$q = \sigma E A (T^4)$$

where E is the emissivity of the body.

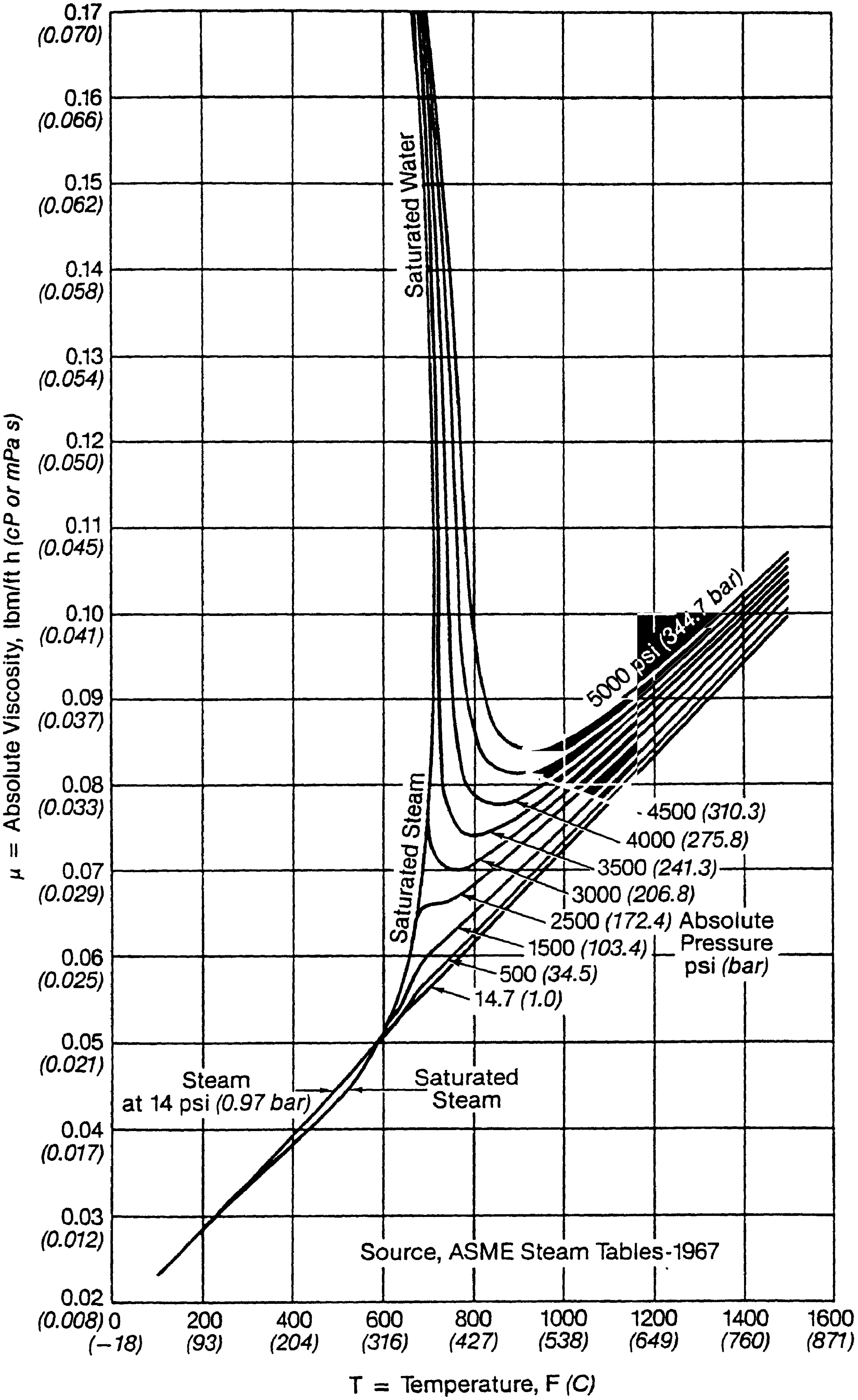
- If we consider two parallel planes of black bodies, then heat transfer by radiation from the hot plane (T, °K) to other plane (T_2, °K) is given by the formula

$$q = \sigma A (T_1^4 - T_2^4)$$

- In addition to 'Flame' giving this radiation, the luminous radiation is produced by burning coal particles and soot etc. Thus, calculation of luminous radiation is complex
- Water vapours CO_2, SO_2 and CO (present in combustion gases) also absorb and emit radiation heat. This is called non-luminous radiation.
- Overall the radiation phenomenon in the boiler furnace becomes very complex, and it is not possible to calculate from first principles the heat absorbed by surfaces (water wall and radiant super heater) in the radiation zone. Thus, calculations are based on experimental research data or the performance design standards/manuals of different boiler manufacturers.



Arrangement factor, F_a, as affected by Reynolds number for various in-line tube patterns, crossflow gas or air.



Source, ASME Steam Tables-1967

Absolute viscosity of saturated and superheated steam.

Chapter 4

Fuels and the combustion stoichiometry

Fuels and the combustion stochiometry

- Coal (as received) properties

Proximate analysis	
Component	% by wt
Moisture	
VM	
FC	
Ash	
Total	100%
Heating value (HCV & LCV)	=Btu/lb or kCal/kg or kJ/kg

Ultimate analysis	
Component	% by wt
Moisture	
C	
H	
S	
N	
O	
Ash	
Total	100%
Range	6000 to 13000 Btu/lb

- Oil

Ultimate analysis	
Component	Wt %
C	
H	
S	
N	
O	
Ash	
Total	100%
HHV	Btu/lb or kCal/kg or kJ/kg
Range	18000 to 20000 Btu/lb

- Natural gas is mixture of CH_4(Methane), C_2H_6(Ethane) & N_2

Ultimate analysis	
Component	% by wt
C	
H	
N	
S	Generally negligible
O	-do-
Total	100%
HHV -Units	**Approx. value**
Btu/ft^3 (at 60°F & 30 in Hg)	1000 to 1150
kJ/m^3 (at 16°C & 102 kPa)	38000 to 42000
Btu/lb	21500 to 23000
kJ/kg	5000 to 54000

- Combustibles in fuels

Element	**Heat of combustion** (btu/lb)
C	14,093 (gross)
H	61095 (gross) 51625 (net)
S	3980 (gross)

- The combustion process

C +	**O_2**	→	**CO_2**
1 mole	1 mole		1 mole
(-)	(1 ft^3)		(1 ft^3)
12 lb	32 lb		44 lb
$2H_2$ +	**O_2**	→	**$2H_2O$**
2 mole	1 mole		2 mole
(2 ft^3)	(1 ft^3)		(2 ft^3)
4 lb	32 lb		36 lb
S +	**O_2**	→	**SO_2**
1 mole	1 mole		1 mole
(-)	(1 ft^3)		(1 ft^3)
32 lb	32 lb		64 lb

- The combustion reaction of different elements/compounds and their heat of combustion is given in table enclosed.

Common Chemical Reactions of Combustion

Combustible	Reaction	Moles	Mass or weight, lb	Heat of Combustion (High) Btu/lb of Fuel
Carbon (to CO)	$2C + O_2 = 2CO$	2 + 1 = 2	24 + 32 = 56	3,950
Carbon (to CO_2)	$C + O_2 = CO_2$	1 + 1 = 1	12 + 32 = 44	14,093
Carbon monoxide	$2CO + O_2 = 2CO_2$	2 + 1 = 2	56 + 32 = 88	4,347
Hydrogen	$2H_2 + O_2 = 2H_2O$	2 + 1 = 2	4 + 32 = 36	61,095
Sulfur (to SO_2)	$S + O_2 = SO_2$	1 + 1 = 1	32 + 32 = 64	3,980
Methane	$CH_4 + 2O_2 = CO_2 + 2H_2O$	1 + 2 = 1 + 2	16 + 64 = 80	23,875
Acetylene	$2C_2H_2 + 5O_2 = 4CO_2 + 2H_2O$	2 + 5 = 4 + 2	52 + 160 = 212	21,502
Ethylene	$C_2H_4 + 3O_2 = 2CO_2 + 2H_2O$	1 + 3 = 2 + 2	28 + 96 = 124	21,636
Ethane	$2C_2H_6 + 7O_2 = 4CO_2 + 6H_2O$	2 + 7 = 4 + 6	60 + 224 = 284	22,323
Hydrogen sulfide	$2H_2S + 3O_2 = 2SO_2 + 2H_2O$	2 + 3 = 2 + 2	68 + 96 = 164	7,097

- Air properties

Average molecular wt = 29

		% by volume	% by wt
N_2	=	79.05	76.86
O_2	=	20.95	23.14

Moisture in the air at RH = 60% & 80°F (26.7°C)

= 0.013 lb water/lb dry air

= 0.0209 mole water/mole of dry ~~water~~ air

- Mole volume

1 lb mole of gas = 359 ft^3

1 gm mole of gas = 22.4 litres

1 kg mole = 22400 litres

= 22.4 m^3

- Examples
  1) Air required for combustion of a fuel (given excess air %)
  2) Wet air required
  3) Flue gas generated (vol%, Wt%) - Comp, volume
  (Table enclosed gives typical excess air requirements at fuel burning equipment)
- Heat of combustion (or calorific value or heating value) - Energy generated by complete combustion of a unit weight of fuel)
  - Solid & liquid fuels with Bomb Calorimeter (HHV) by method of heat absorption by the cooling medium
  - Gases with constant flow type calorimeter
- Theoretically, Higher Heating Value (HHV) by Dulong's formula

$$HHV = \{14544 + 62028\,[H_2 - (O_2/8)] + 4050\,S\} \quad \text{Btu/lb}$$

C, H_2, O_2 & S as weight %

Lower heating value (LHV) = HHV - Heat content of water vapours formed due to combustion of hydrogen
or Net Calorific Value

(base temp. 68°F)

- $LHV = \{HHV - 10.30(H_2 \times 8.94)\}$ Btu/lb

Boiler efficiency

$$= \frac{\text{Output energy (in the form of steam)}}{\text{Input energy (in the form of fuel)}} \times 100$$

$$= \frac{\text{(Mass flow rate of steam)} \times \text{(Enthalpy gain from feed water to superheated steam)}}{M_f \times \text{HHV}} \times 100$$

where M_f = Mass flow rate of fuel

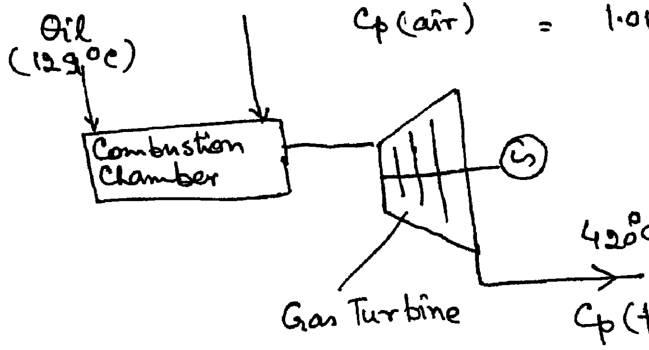
- It is difficult to correctly determine the mass feed rate of solid fuel as it is a heterogeneous mass and its bulk density keeps on changing from time to time
- Thus, boiler efficiency in case of solid fuels is measured generally by Indirect method (through calculation of losses) as per standard method defined by ASME PTC 4/BS 2885/IS 8753. There is hardly any difference in the three standards.

Typical Excess Air Requirements at Fuel Burning Equipment

Fuel	Type of Furnace or Burners	Excess Air % by wt
Pulverized coal	Completely water-cooled furnace — wet or dry ash removal	15 to 20
	Partially water-cooled furnace	15 to 40
Crushed coal	Cyclone furnace — pressure or suction	13 to 20
	Fluidized-bed combustion	15 to 20
Coal	Spreader stoker	25 to 35
	Water-cooled vibrating grate stoker	25 to 35
	Chain grate and traveling grate	25 to 35
	Underfeed stoker	25 to 40
Fuel oil	Register type burners	3 to 15
Natural, coke oven and refinery gas	Register type burners	3 to 15
Blast furnace gas	Register type burners	15 to 30
Wood/bark	Traveling grate, water-cooled vibrating grate	20 to 25
	Fluidized-bed combustion	5 to 15
Refuse-derived fuels (RDF)	Completely water-cooled furnace — traveling grate	40 to 60
Municipal solid waste (MSW)	Water-cooled/refractory covered furnace reciprocating grate	80 to 100
	Rotary kiln	60 to 100
Bagasse	All furnaces	25 to 35
Black liquor	Recovery furnaces for Kraft and soda pulping processes	15 to 20

EXAMPLES

Air (25°C, RH = 60%, 0.013 kg H_2O/kg dry air)
Cp (air) = 1.01 kJ/kg (K)



Cp (flue gas) = 1.11 kJ/kg (K)

- Enthalpy of saturated steam at 0.01 atm & 420°C = 3308 kJ/kg
- Composition of flue gas (vol%)
  CO_2 = 4.93 %
  O_2 = 14.31 %

Oil

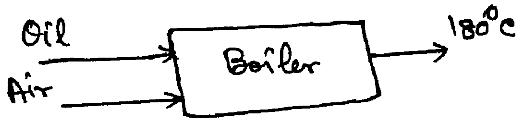
HHV = 41.7 MJ/kg
Cp = 1.97 kJ/kg (K)
Firing rate = 1000 kg/h

Composition of Oil

Element	Wt %
C	86.50
H	13.00
S	0.38
O	0.04
N	0.08
	100.00

---

i.



- Flue gas composition (Vol%)
  CO_2 = 14 %
  O_2 = 2.0 %
- Enthalpy of saturated steam at 0.01 at & 180°C = 2840 kJ/kg

---

Questions: For the above two cases, calculate

i, Excess air at which combustion is taking place.
ii, Composition of flue gas (Vol%, Wt%)
iii, Air requirement (dry) and flue gas produced (dry) per tonne of fuel
iv, Air requirement (wet) and flue gas produced (wet) per tonne of fuel
v, Work done/Energy absorbed in Gas Turbine (Boiler)
vi, Thermal efficiency of Gas Turbine (Boiler)

SOLUTION (Problem I)

Fuel Comp.	Wt %	Moles (Basis: 100 kg of fuel)	
C	86.50	86.50/12	= 7.208
H	13.00	13.0/2	= 6.50
S	0.38	0.38/32	= 0.012
O	0.04	0.04/32	= 0.00125
N	0.08	0.08/28	= 0.00286

Flue gas
Vol% / Mole%
$CO_2 = 4.93$
$O_2 = 14.31$

From C-balance between the fuel & flue gas,
amount of fuel that will produce 4.93 moles of $CO_2 = 100 \times \frac{4.93}{7.208} = 68.4$ kg

Now BASIS of all calculations for mass balance is 68.4 kg of fuel.

- Stochiometric flue gas composition

Moles

$CO_2 = \frac{68.4}{100} \times 7.208 = 4.93$

H_2O (combustion of H_2) $= 0.684 \times 6.5 = 4.446$

$SO_2 = 0.684 \times 0.012 = 0.008$

- O_2 required for stochiometric combustion

	Moles
For C	4.93
H_2	2.223
S	0.008
Total:	7.161

O_2 in the fuel $= 0.00125 \times 0.684 = 0.0008 \simeq 001$ moles

Net O_2 required for stochiometric combustion $= 7.161 - 0.001$
$= 7.160$ moles

- Excess air calculation:

O_2 in flue gas (even after stochiometric combustion) = 14.31 moles

$\therefore$ Total O_2 supplied $= 7.160 + 14.31 = 21.47$ moles

$$\text{Excess air } (\%) = \frac{21.47 - 7.160}{7.160} = 199.86\%$$

- N_2 in flue gas $= \frac{79}{21} \times 21.47 = 80.76$ moles

Total air supplied $= \frac{100}{21} \times 21.47 = 102.238$ moles.

N_2 in fuel $= 0.00286 \times \frac{68.4}{100} = 0.002$ moles

$\therefore$ Total N_2 in flue gas $= 80.76 + 0.002 = 80.762$ moles

- Total air (dry) for 68.4 kg of fuel $= 102.238 \times 29 = 2964.9$ kg

$\therefore$ dry air / kg of fuel $= 2964.9/68.40 = 43.346$ kg

Moisture in air = 0.013 kg | kg of air

$= \frac{0.013}{18}$ moles | $\frac{1.0}{29}$ moles of air

$= \frac{0.013}{18} \times 29$ moles | mole of air

= 0.0909 moles | mole of air

∴ Total moles of moisture in air = 102.238 × 0.0909

= 2.137 moles

= 2.137 × 18 = 38.462 kg

∴ Total air (wet) / kg of fuel $= \frac{2964.9 + 38.462}{68.4} = 43.908$ kg

Total moisture in flue gas = 4.446 + 2.137 = 6.583 moles.

Flue gas composition (mole % or vol %) and (Wt %)

Vol %		Gases	moles	Weight (kg)		Wt %	
Wet	Dry					Dry	Wet
4.62	4.93	CO_2	4.93	× 44	= 216.92	7.39	7.10
0.007	0.008	SO_2	0.008	× 64	= 0.51	0.02	0.02
13.43	14.31	O_2	14.31	× 32	= 457.92	15.59	14.99
75.77	80.76	N	80.762	× 28	= 2261.28	77.00	74.01
	100.00	Total (dry)	100.00		2936.63	100.0	
6.18		H_2O	6.583	× 18	118.49		3.88
100.00		Total (wet)	106.583		3055.12		100.00

Contd. – page 4

HEAT BALANCE

Oil consumption = 1000 kg/h

Ambient temperature = $25^\circ C$

Heat input due to combustion of fuel = 41.7×1000

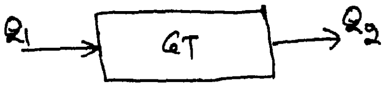
= 41,700 MJ/h

Heat input through specific heat of oil = $1000 \times 1.97 \times (129-25)$ kJ/h

= 204.88 MJ/h

Total heat input, Q_1 = 41,700 + 204.88

= 41,904.88 MJ/h



Heat exiting the GT (dry flue gas) = $1000 \times \left(\frac{2936.63}{68.4}\right) \times 1.11 \times (420-25)$

= 18,824.05 MJ/h

Heat exiting the GT (through moisture) = $1000 \times \left(\frac{118.49}{68.4}\right) \times 3308$ kJ/h

= 5730.48 MJ/h

Total heat exiting the GT, Q_2 = 18,824.05 + 5,730.48

= 24,554.53 MJ/h

∴ Thermal efficiency of GT = $\frac{41904.88 - 24554.53}{41,904.88} \times 100$

= 41.40%

- Application of steam
  - Process heating
  - Power generation
  - Process heating + Power generation

- Specific application and its capacity rating decides the steam conditions and feed water temperature

  m = mass flow rate, TPH

  P = pressure of steam , kg/cm^2

  T = temperature of steam, °C

  T_s = saturation temperature of steam, °C

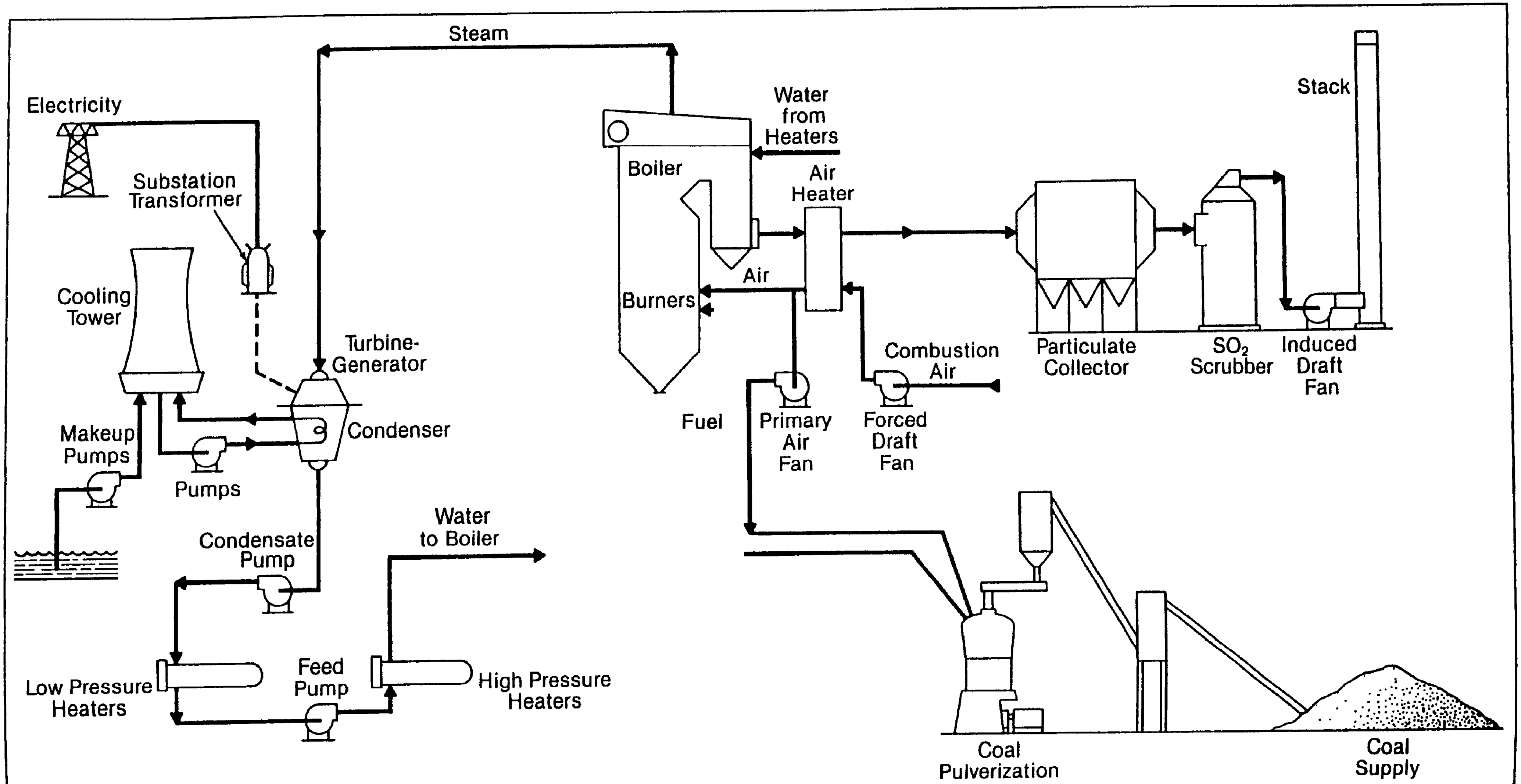
  $(T-T_s)$ = degree of superheat of steam, °C

  T_{FW} = temperature of steam, °C

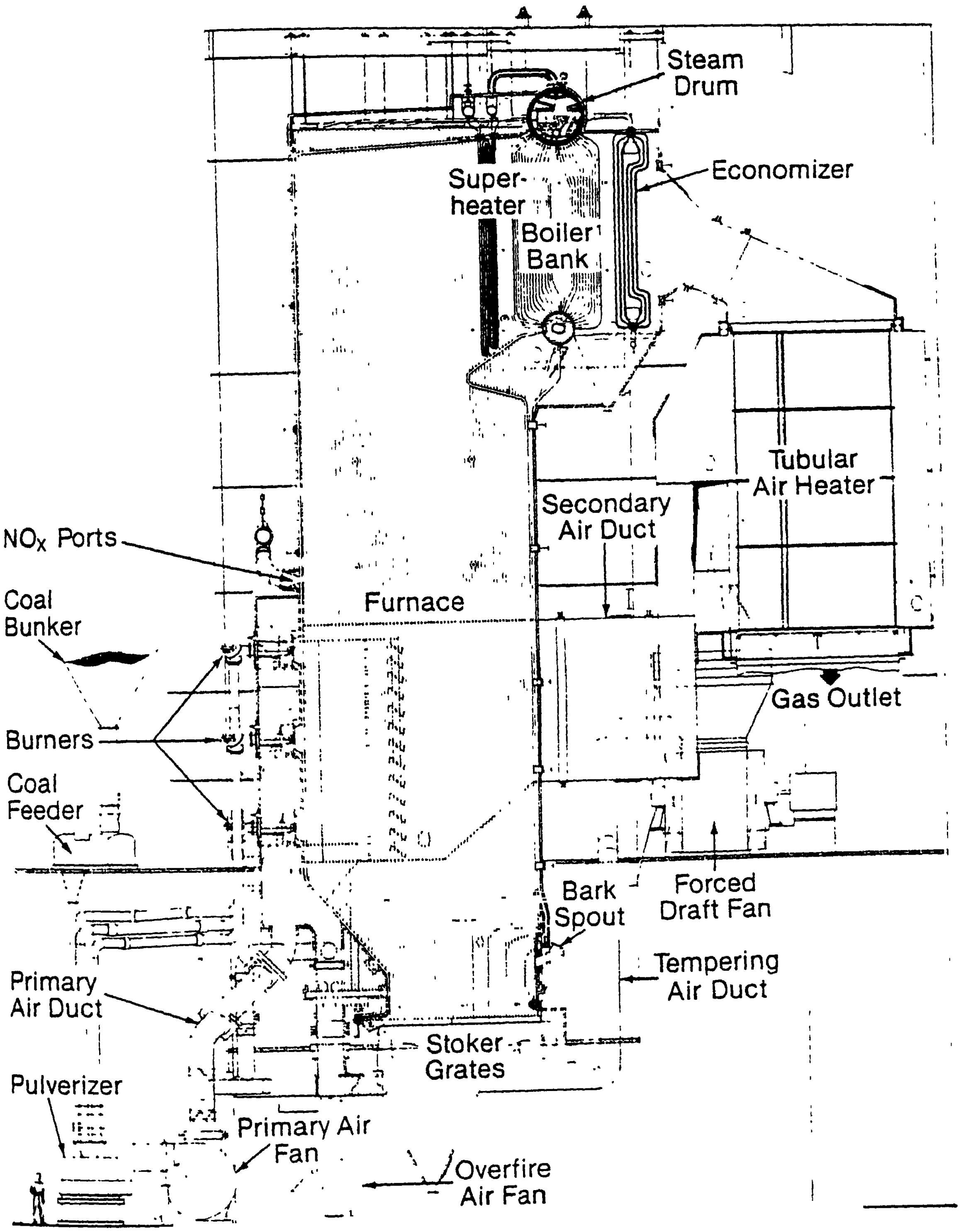
  $(T_{IPI} - T_{HPO})$ = degree of reheat of steam, °C

  T_{HPO} - steam temp at the outlet of HP section of turbine system

  T_{IPI} - steam temp at inlet of IP section of turbine system



(Not Shown: Reheater, Ash and Reagent Handling and Sludge Disposal)



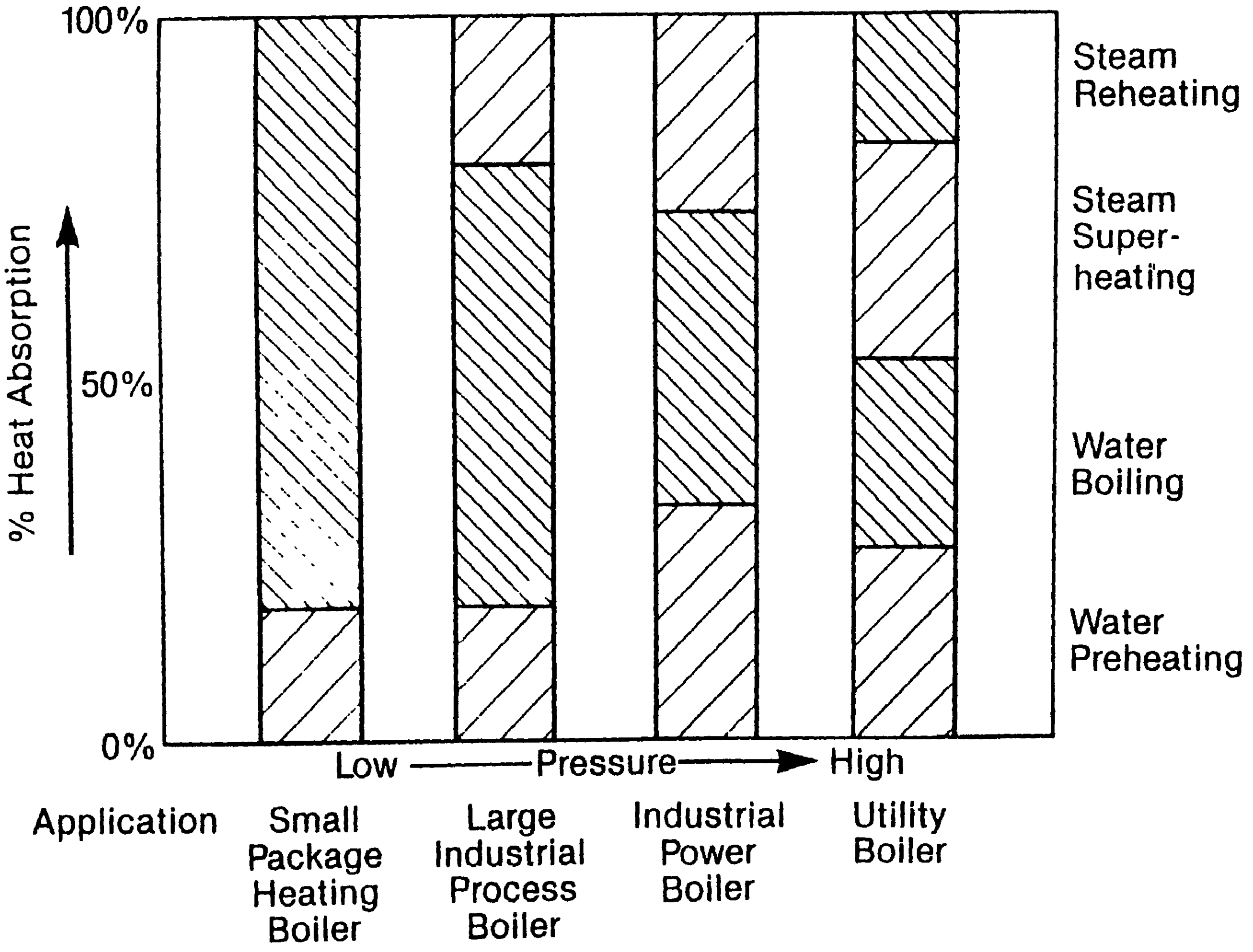
Large industrial power boiler with multiple fuel capability.

- Heat generated by combustion of fuel is absorbed for

	Boiler section
Heating boiler feed water from T_{FW} to T_S	Economiser + Evaporator (partly)
Converting saturated water to saturated steam (latent heat absorption)	Evaporator
Heating steam from T_s to T, the required final steam temperature	Superheater
Reheating steam from T_{HPO} to T_{IPI}	Reheater

- Energy absorption for different sections (Economizer, Evaporator, Superheater, Reheater) is different for different application of the boiler

  (see figure attached)
- The size (design) of each section also varies with the fuel fired (solid/liquid/gas)
- Fuel handling, its preparation and feeding to boiler is also different for different types of fuels.



Steam generator energy absorption by function.

- Selection of type or boiler

  a) Shell type of Flue tube

  - For small capacity rating & low pressure

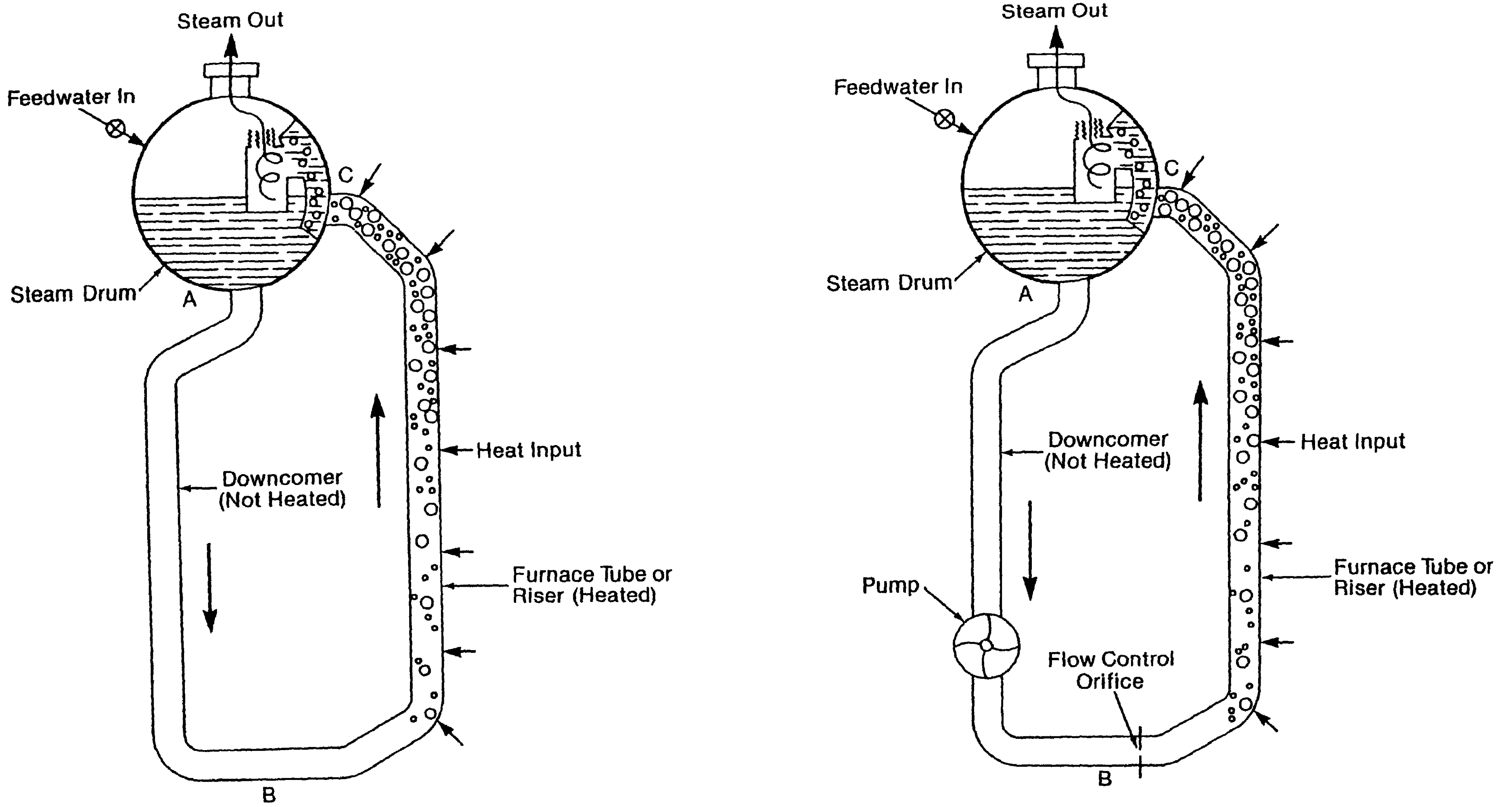
  b) Water tube drum type (natural or forced circulation)

  - For high capacity rating and pressures lower than critical pressure (219 ata)

  c) Water tube once-through type (forced circulation only)

  - for high capacity rating and pressures above critical pressure

- Boiler dynamics
  - Start up
  - Shut down
  - Load control and load throw-off



(a) Simple Natural or Thermal Circulation Loop

(b) Simple Forced or Pumped Circulation Loop

Simple circulation systems.

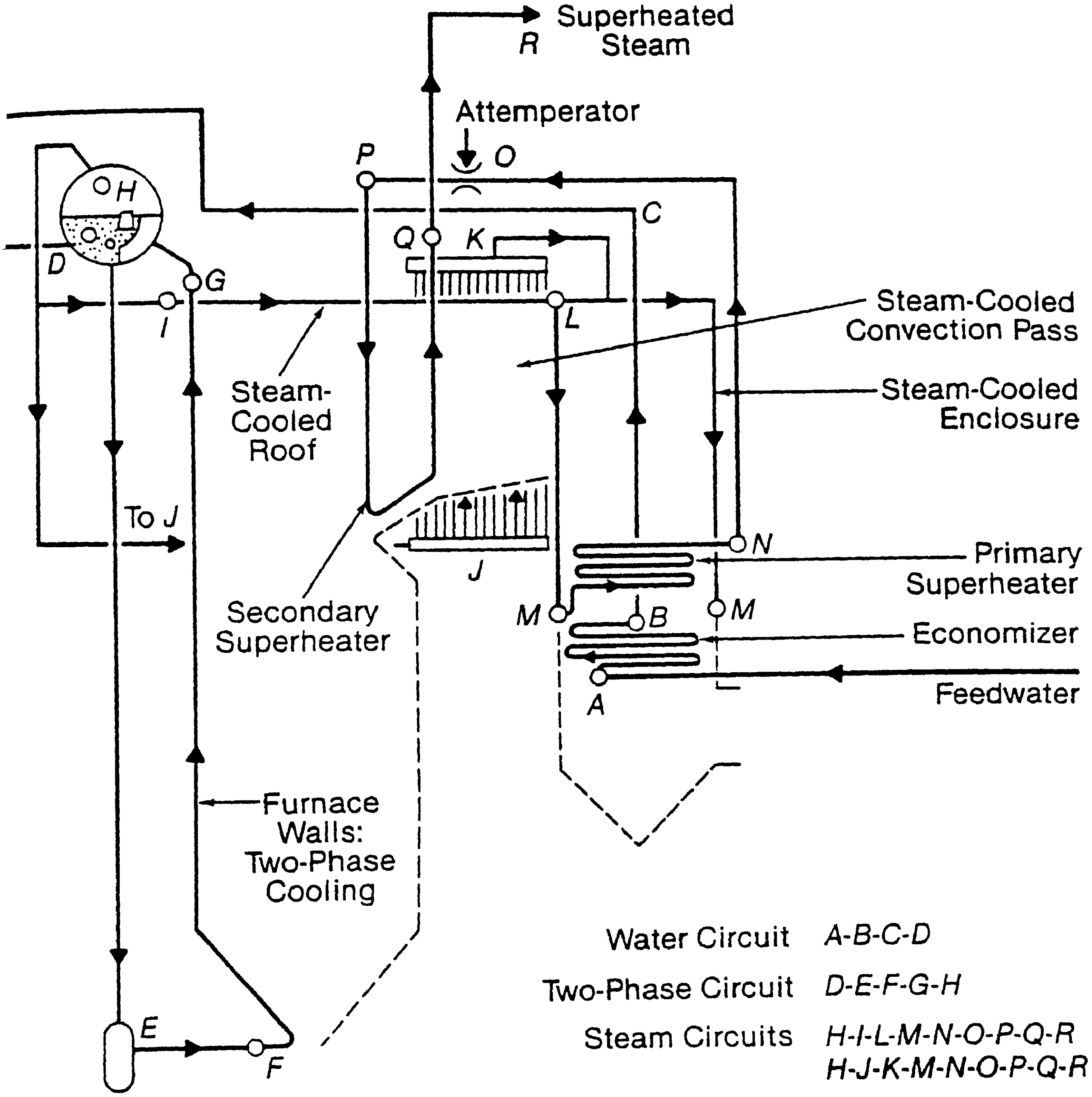
Fossil fuel steam generator components

a) For generating steam and maximum possible heat recovery

1 Furnace & convection pass (or tube bank)
2 Steam superheater
3 Steam reheater
4 Economiser
5 Steam drum
6 Deaerator
7 Feed water pump, & drum level controls
8 Air preheater
9 Superheat temperature attemperator, & its controls

b) Non-steam generating components

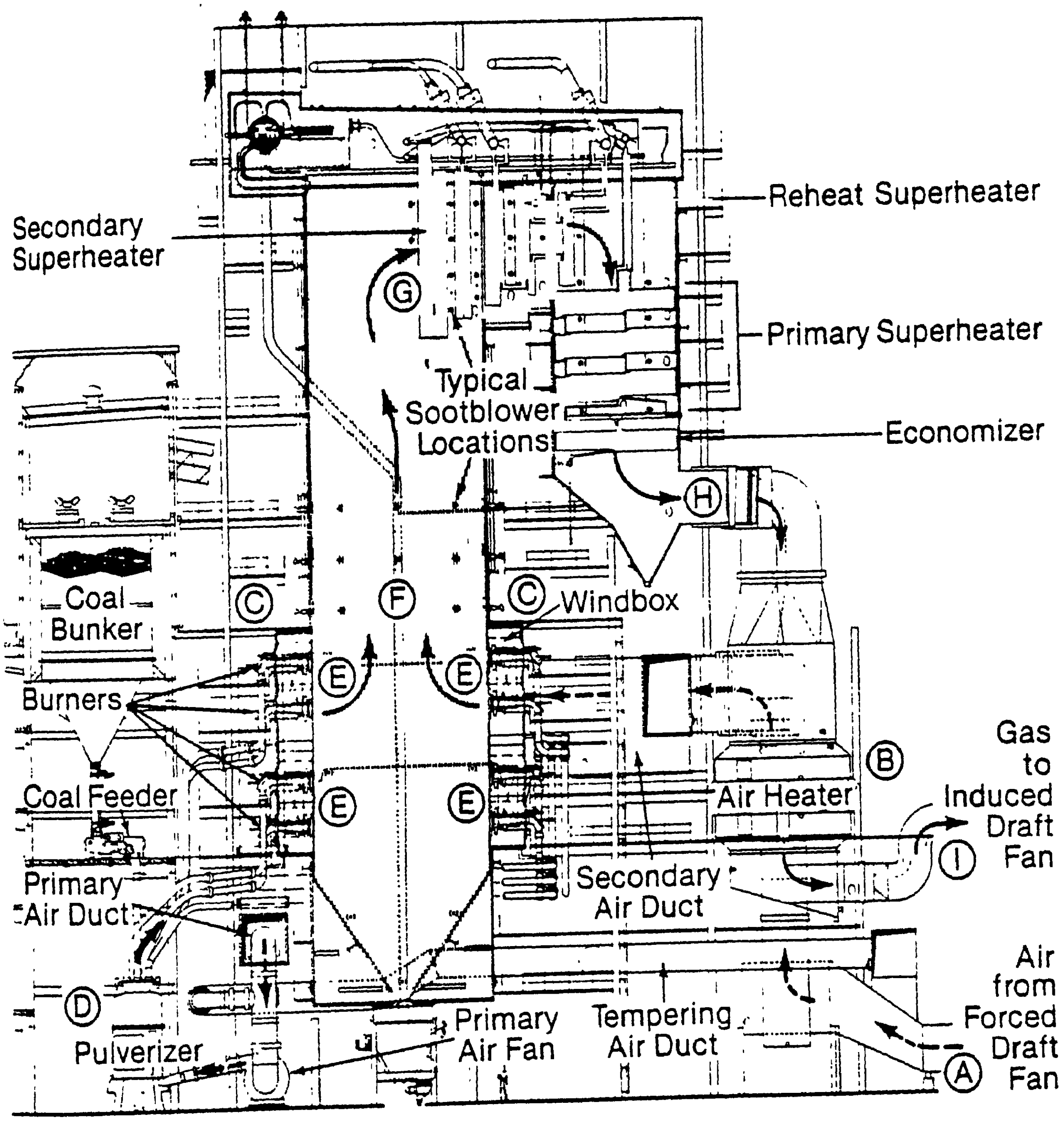
1. Fuel preparation: Feeder, crushers, pulverisers
2. Combustion system: Burners, flame scanners, windbox, controls
3. Air/gas side system: fans, ducts, dampers, controls
4. Other equipment
   - soot blowers
   - pollution control system
   - ash collection & transport
   - controls w.r.t steam end us



Coal-fired boiler steam-water circulation system.

Gasflow system in a boiler

- Air supplied by forced draft (FD) fan to air heater where it is heated to recover heat from outgoing flue gases. Hot air also helps combustion
- 70-80% hot air goes to windbox of burners
- 20-30% passes through PA (booster) fans to the coal pulvisers (mills) for drying the coal while grinding. This, then, carries the pulversied coal to burners.
- Coal and air mixture is rapidly mixed and burned in the furnace.
- Flue gas pass up the furnace where these are being cooled primarily through radiation through furnace walls till it reaches the furnace exit
- Flue gas then passes through superheaters, reheaters and economisers before leaving the steam generator enclosure



Coal-fired boiler air/gas flow path.

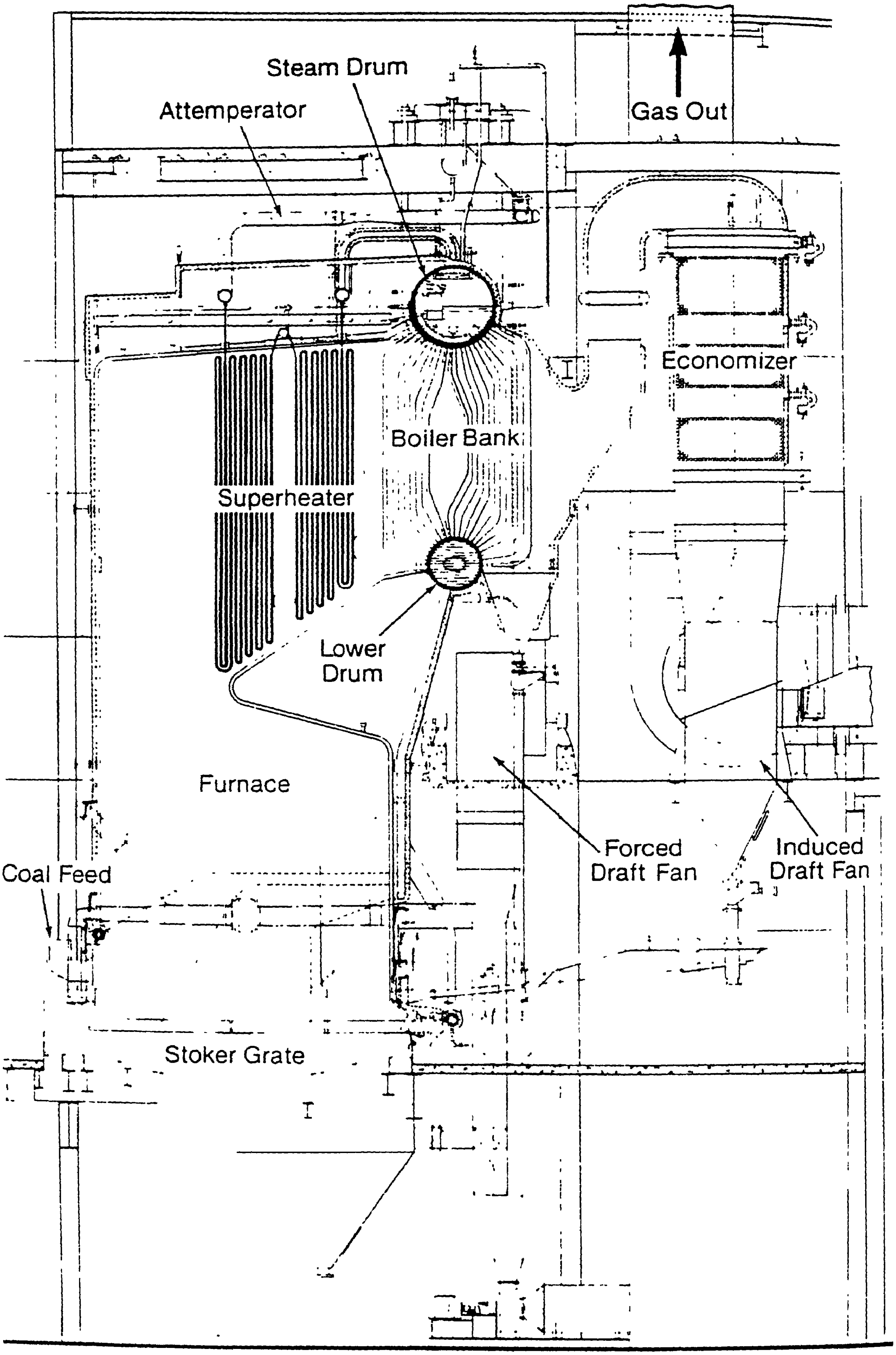
Chapter 6

Fuel firing system for solid fuels

A. Grate firing

1. Moving grate
2. Spreader stoker with vibrating grate

- Used for coal, wood, bagasse, biomass, municipal solid waste
- Steam generating capacity
  - coal: up to 180 TPH
  - wood and bagasse: up to 250 TPH
  - Pressure and temperature up to 124 bar and 538°C
- See figure for a typical design



Two drum Stirling˜ boiler for spreader-stoker firing.

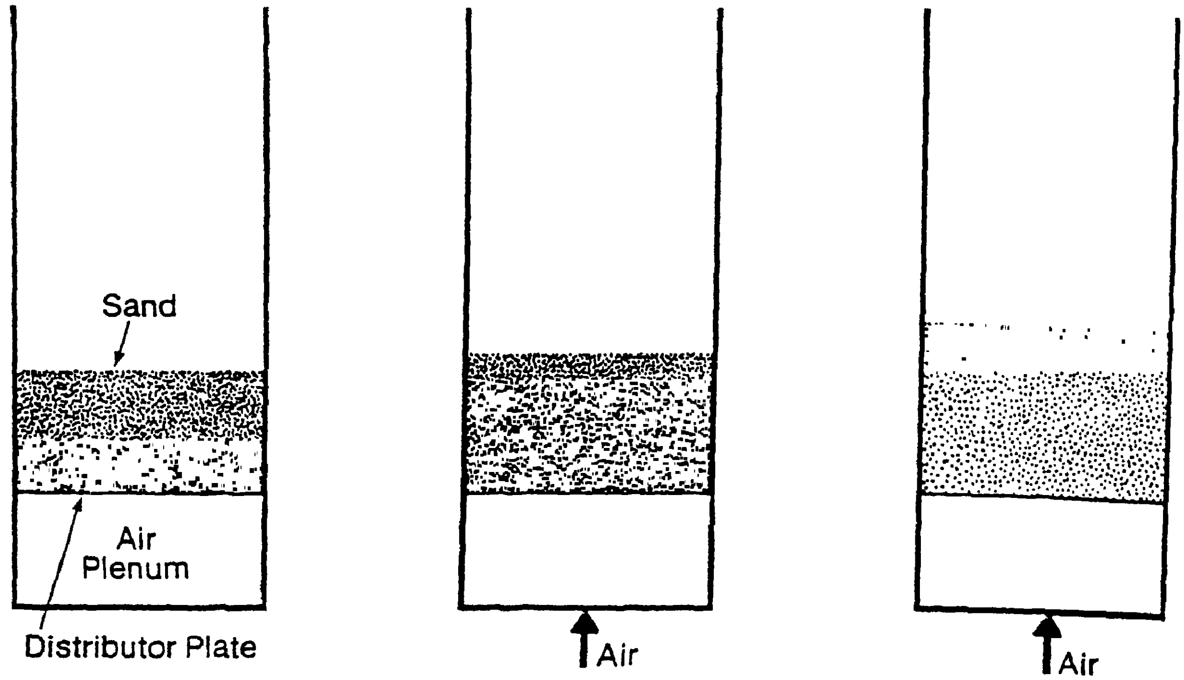
B. Atmospheric Fluidised Bed Combustion (AFBC)

- Concept (refer figures attached)
- Used for coal, wood, biomass, MSW, Sewage sludge
- Fluidising velocity (superficial gas velocity) range 1 to 3.7 m/s
- Advantages
  - Burns low grade fuels (HHV as low as 1600 kCal/kg)
  - Low NOx due to low temp combustion (850–900°C)
  - Fuel flexibility
  - Controls SO_x emission

    $CaCO_3$+766 Btu/(lb) of $CaCO_3 \rightarrow CaO + CO_2$

    $CAO + \frac{1}{2}O_2 + SO_2 \rightarrow CaSO_4$ + 6733 Btu/(lb) of suphur

    Sulphur capture 90 to 95% with Ca/S molar ratio of 3 to 3.5 steam.
  - Low coal milling cost (coal size required is 6 mm)
- Steam capacity up to 600 TPH (200 TPH in India), 124 bar 538°C



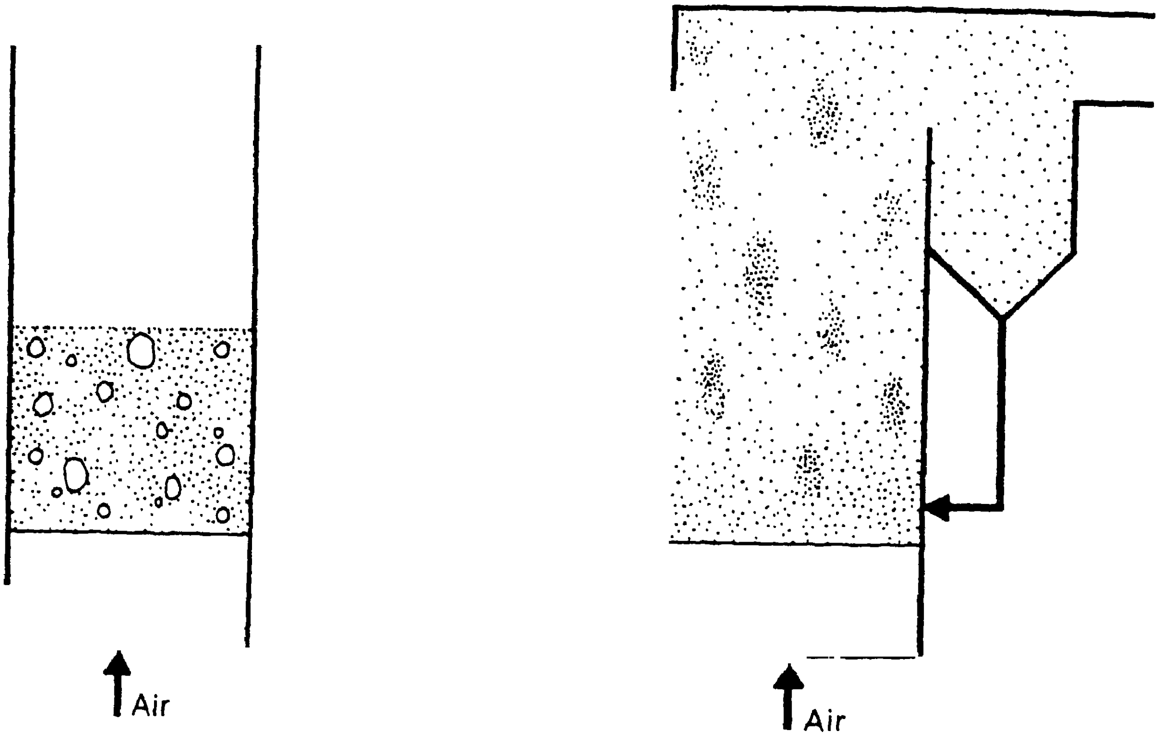
(a)

Fixed Bed

(b)

Minimum Fluidization

(c)



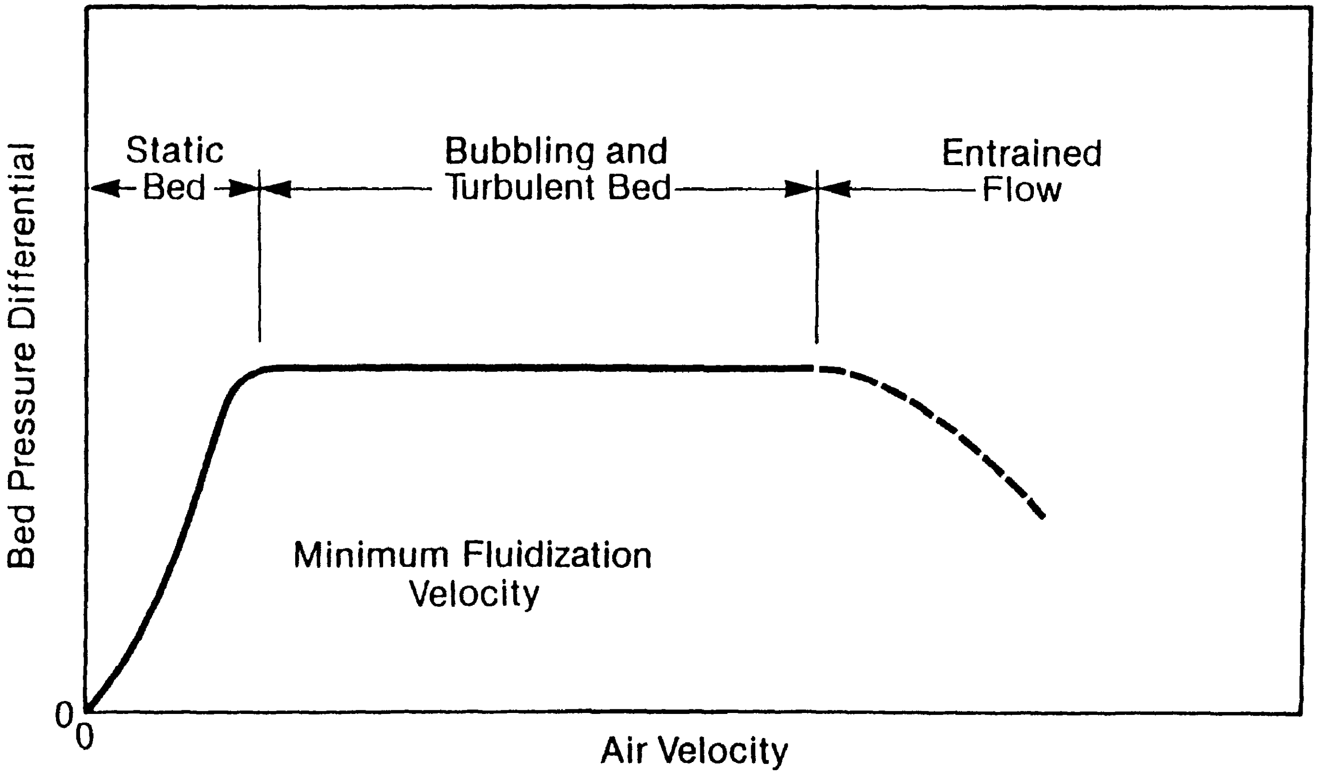
Bubbling Bed

(d)

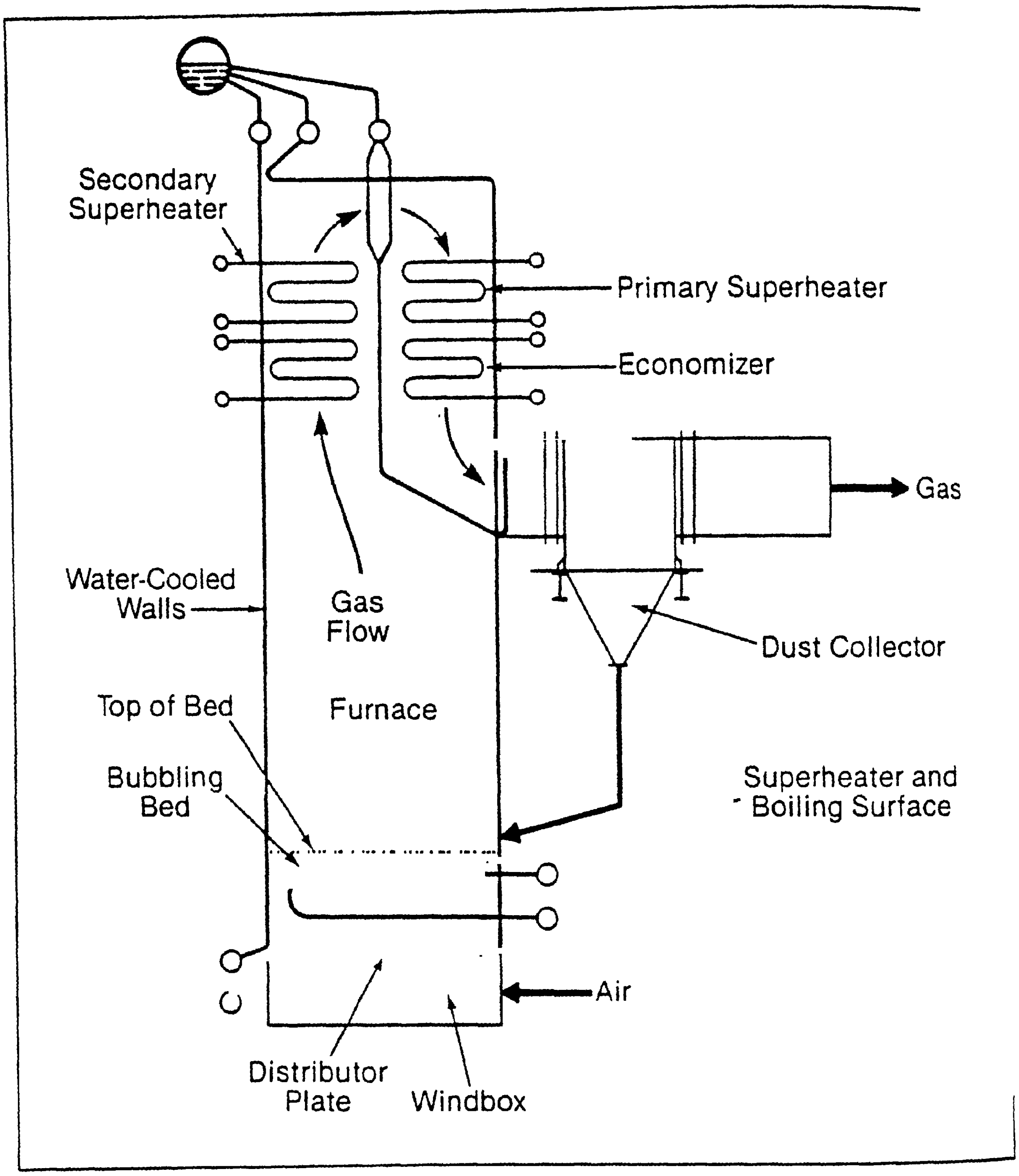
Circulating Bed

(e)

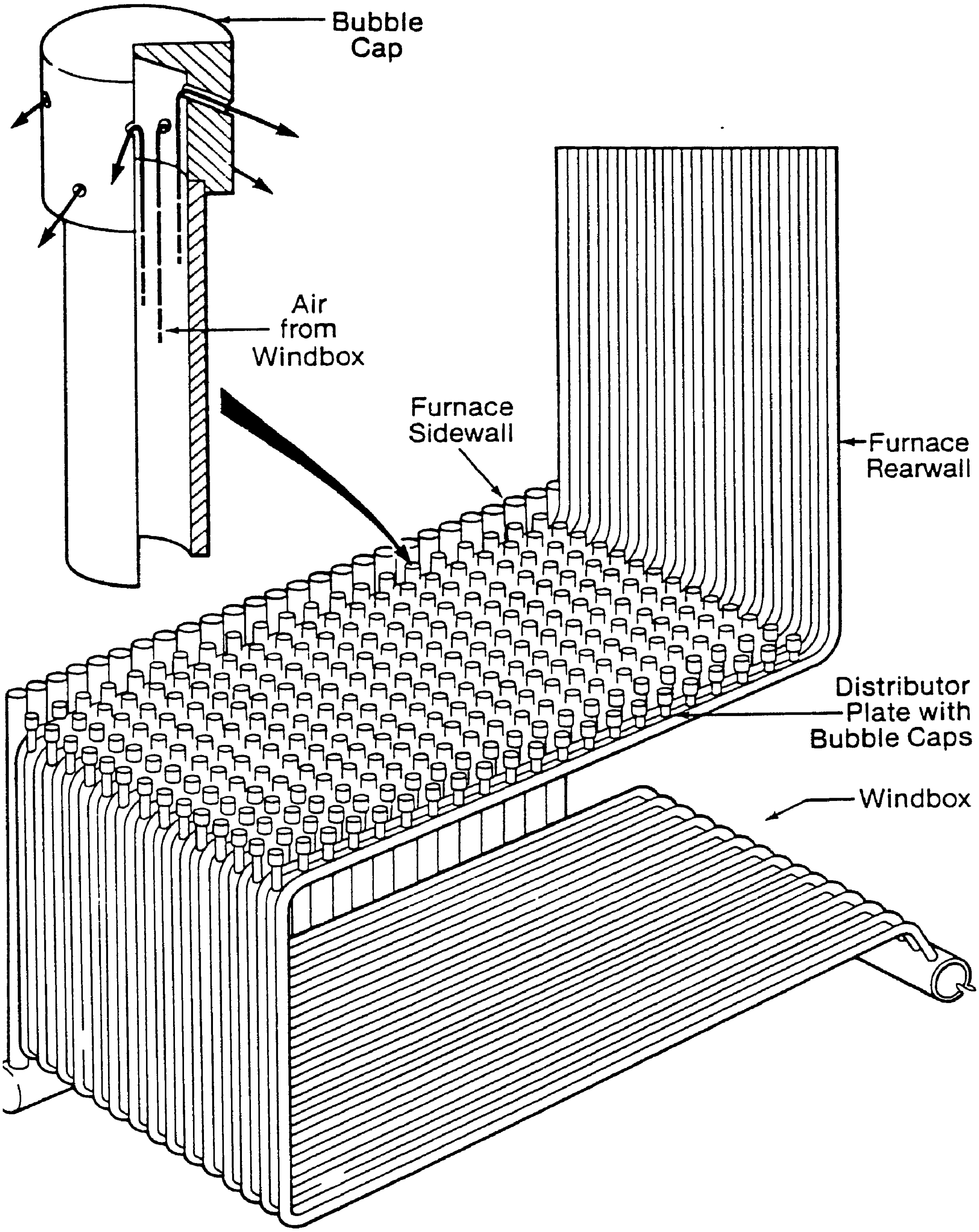
Typical fluidized-bed conditions.



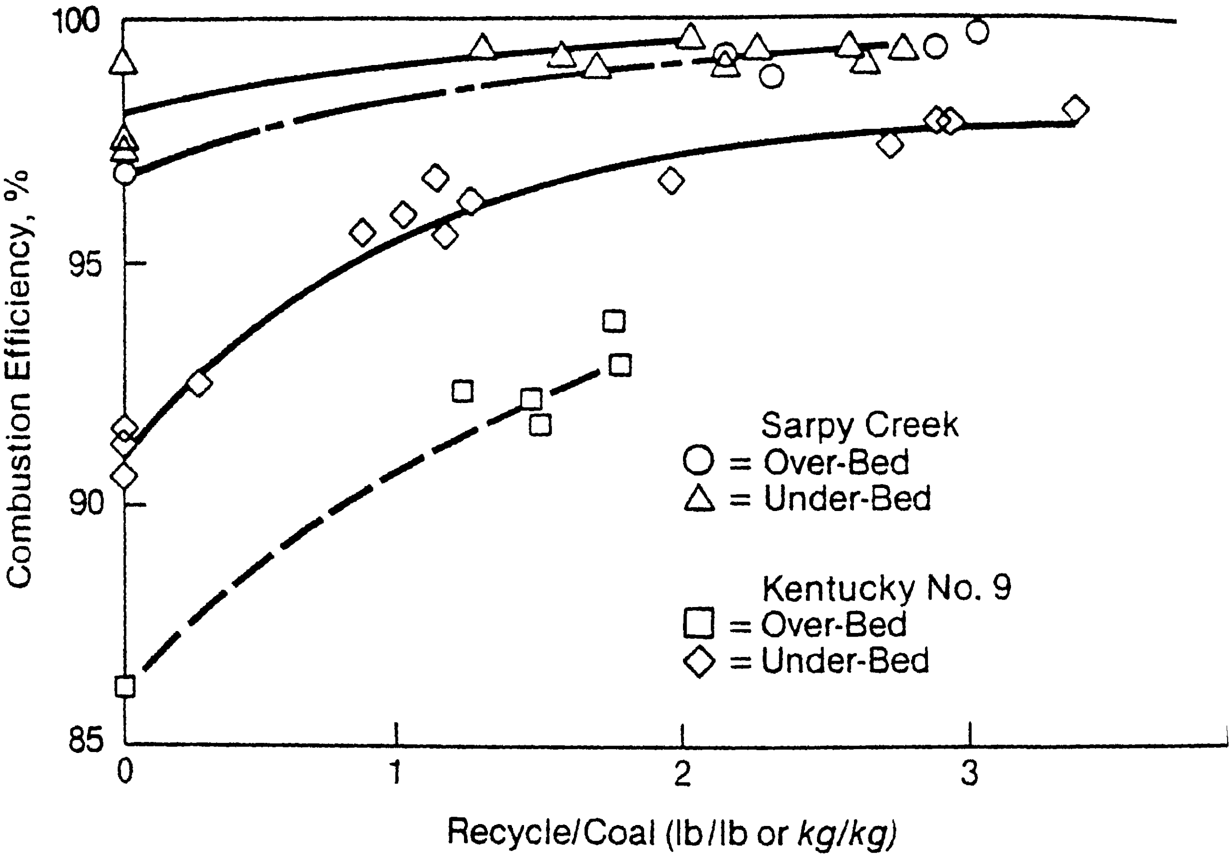
Effect of velocity on bed pressure drop.



Typical bubbling fluidized-bed boiler schematic.



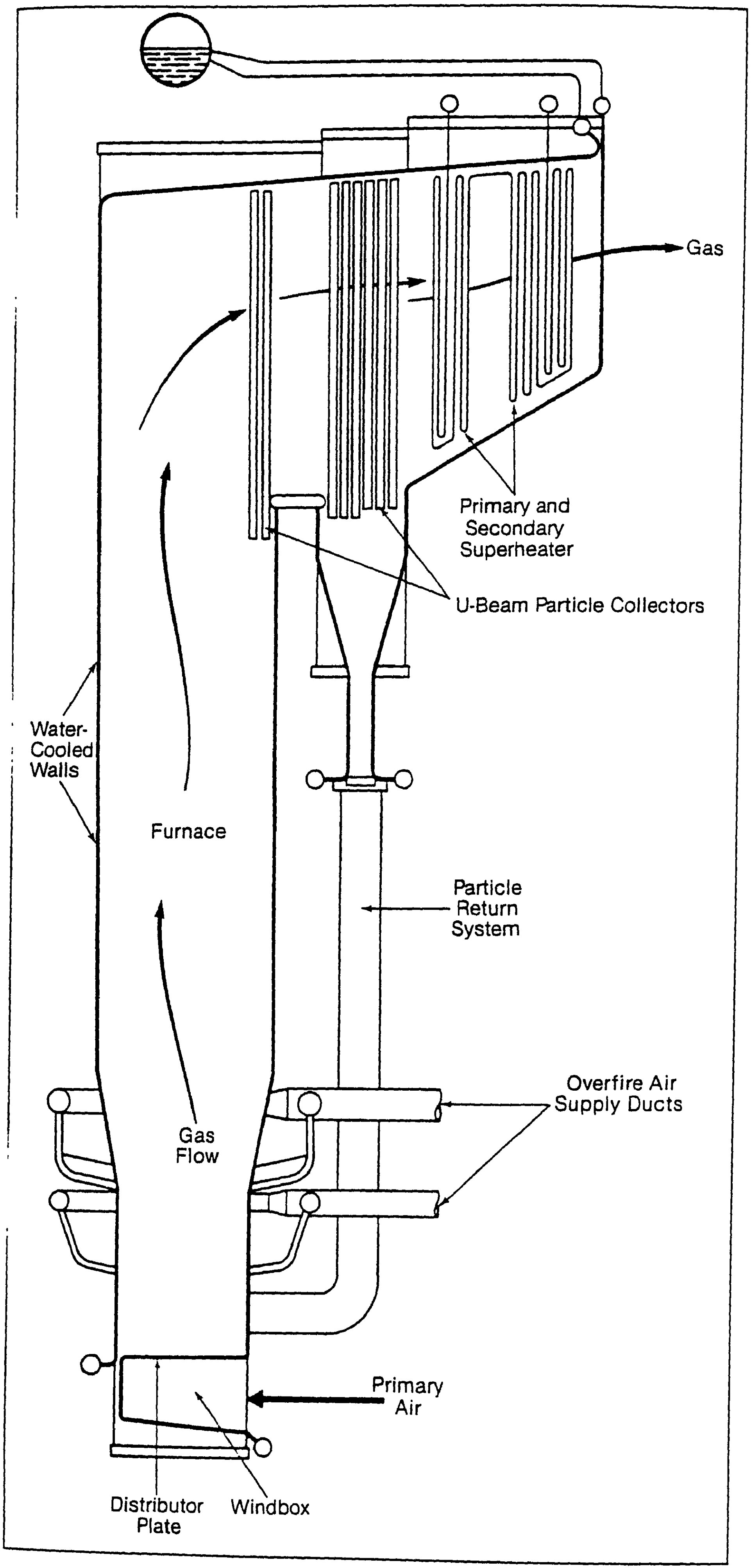
Furnace distributor plate and bubble caps.



Comparison of under-bed and over-bed coal feed.

C. Circulating Fluidised Bed Combustion (CFBC)

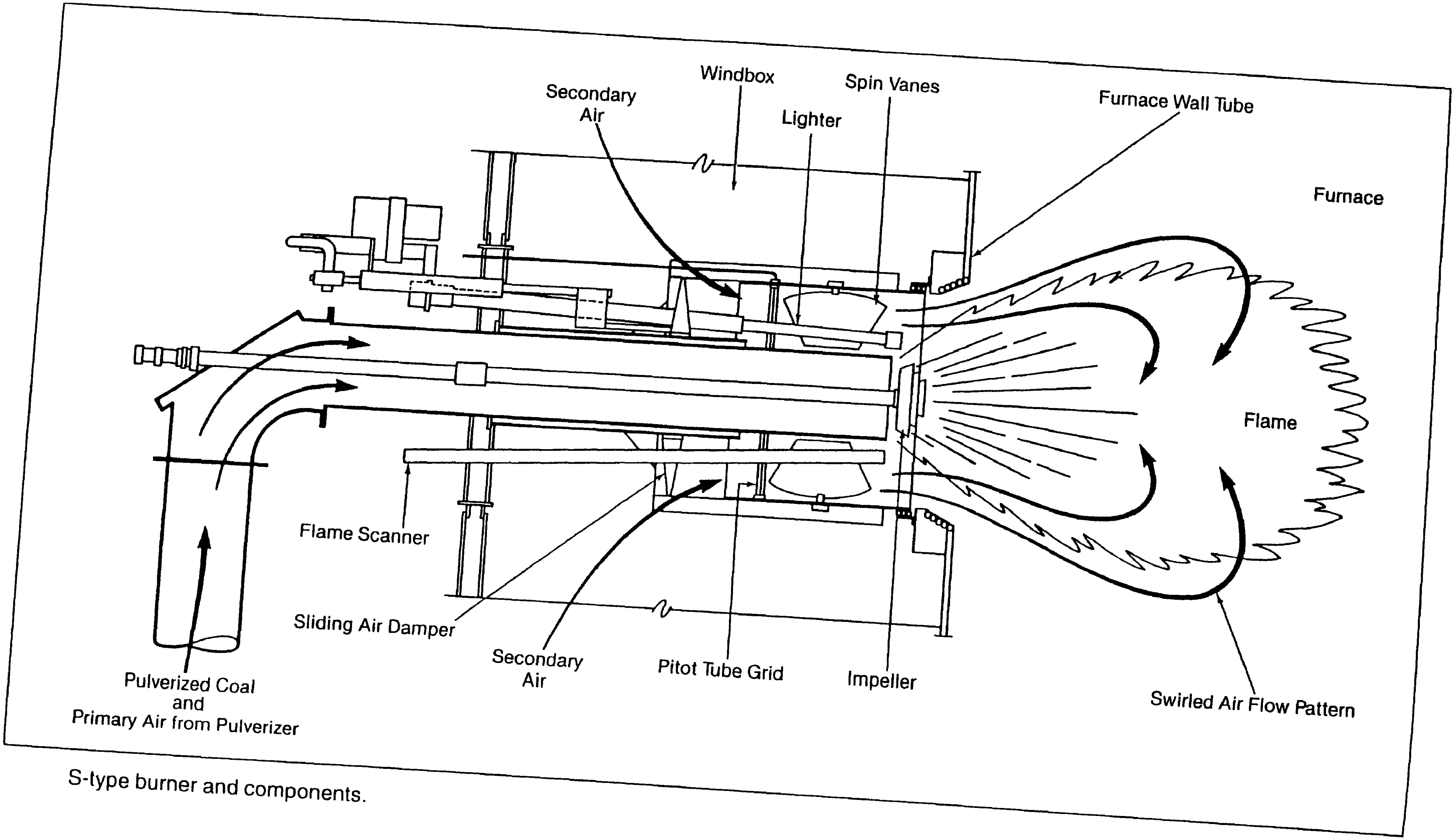
- Concept (refer figures enclosed)
- Used for coal, wood, biomass, MSW, sewage sludge
- Fluidising velocity (superficial gas velocity) range 3.7 to 9.1 m/s
- High combustion efficiency (close to pc fired units) due to recycle of fines from hot cyclones to the furnace
- Sulphur capture more than 95%, with Ca/S molar ratio of 2 to 2.5
- No inbed tubes; only external bubbling FB heat exchanger in some designs
- Steam capacity above 90 TPH and up to 740 TPH 160 bar, 565°C



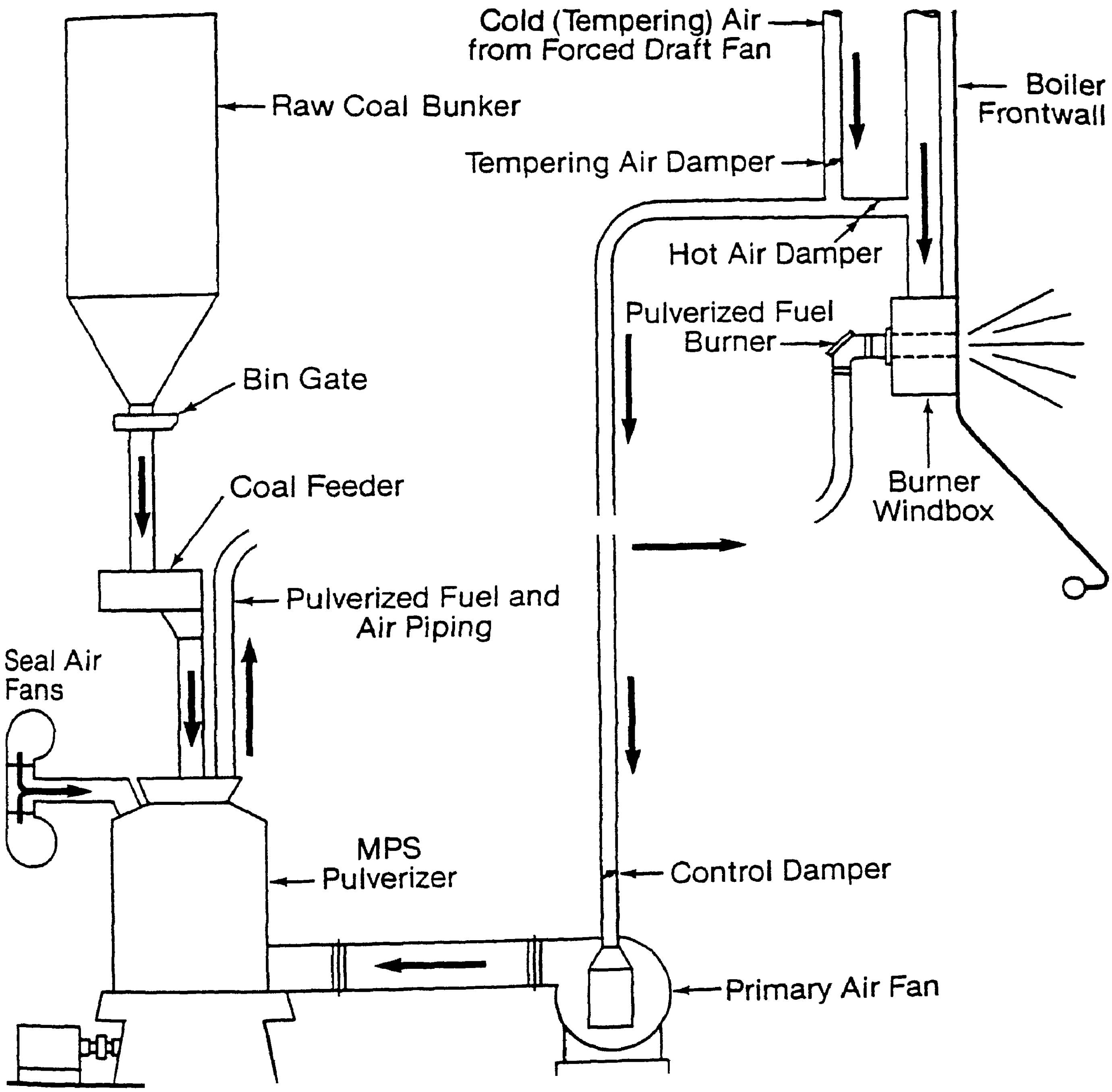
Typical circulating-bed boiler schematic.

D. Pulverised coal (PC) firing

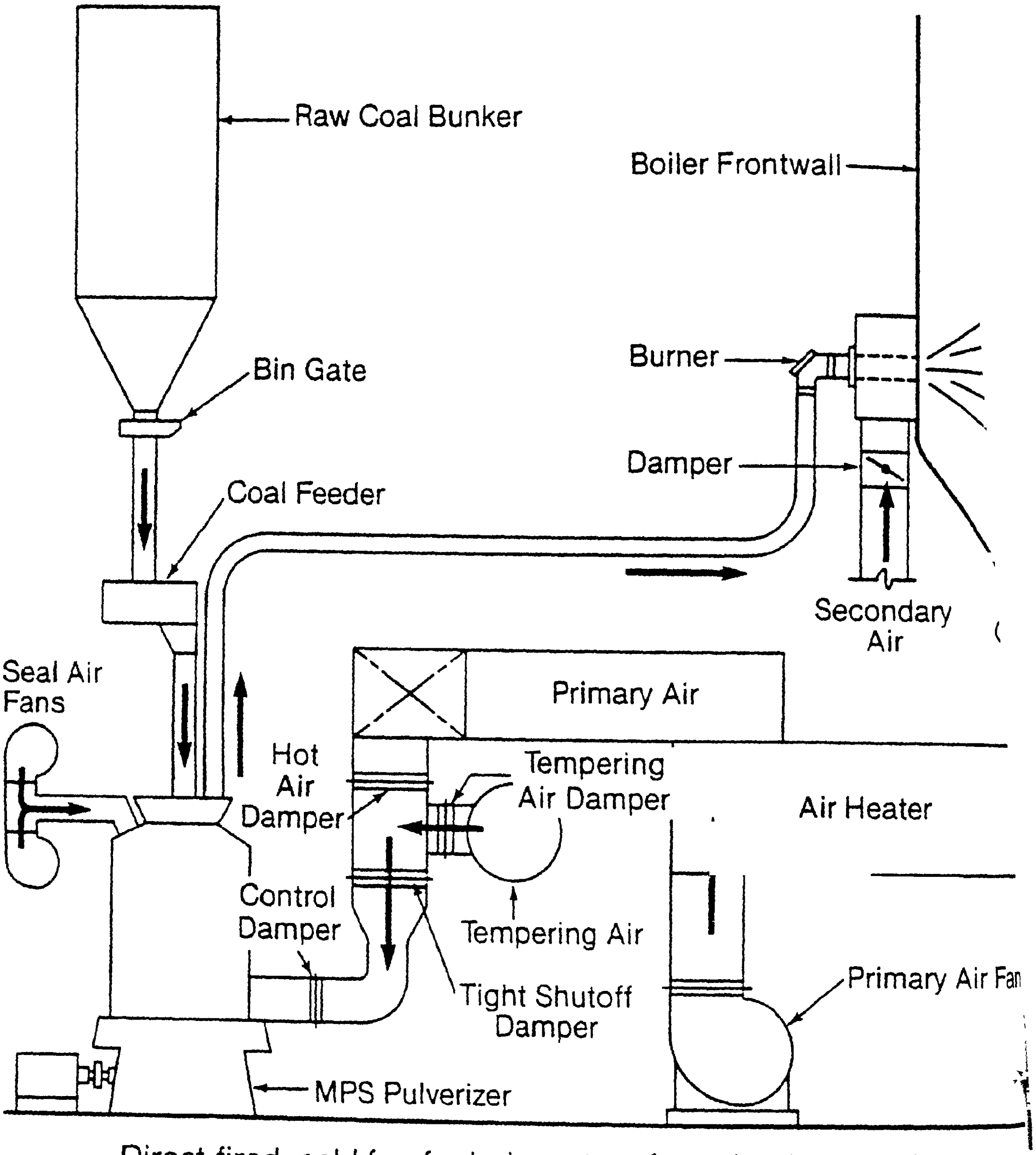
- Concept (refer figures enclosed)
- Direct firing (pc from mill to burners)
- Essential elements of pc firing systems are
  - a raw coal feeder that regulates the coal flow from bunker to the pulveriser
  - a heat source that pre-heats the primary air for coal drying
  - a primary air fan ahead of the pulveriser
  - a pulveriser
  - piping that directs the coal and primary air from pulversier to burners
  - burners that mix the coal and balance of combustion of air
  - controls and regulating devices
- Corner firing (ABB-CE) and wall firing concepts (B&W)
- Fineness of pulverised coal
  - 70% passing through 200 mesh (75 micron) sieve
- Pulveriser outlet temperature control
  - 66-82°C for low volatile matter coal
  - 60-66°C for medium/high volatile matter coal
- Velocity in coal pipes (15 m/s) to burners



S-type burner and components.



Direct-fired, hot fan system for pulverized coal.



Direct-fired, cold fan,fuel-air system for pulverized coal.

Steam 40 / *Coal Pulverization*

Chapter 7

Testing efficiency of fired boilers

Testing efficiency of fired boilers

- Tests at MCR parameters (steam flow, temperature and pressure), no blow-down during test, test period 4 hrs.
- Indirect (loss) method: BS 2885 or based on HHV/LHV or ASME PTC 4 or IS 8753
- Coal sample- Every 15 mts from the feeders for one hour, make representative samples of 1 kg through coning and quartering
- Efficiency generally on HHV basis
- Efficiency defined as follows:

$$\text{Efficiency} = \frac{E_{out}}{E_{in}}$$

E_{out} = The energy the feedwater has picked up for generating steam at specific temperature and pressure (No blow-down during testing)

E_{in} = The energy going into the boiler (based on fuel burnt)

- Efficiency is based on loss method or indirect method, as it is not possible to find accurately the feed rate of fuel, particularly the solid fuels. Thus,

  Efficiency = 100-losses
- Following losses are considered
  - L_{comb} = Loss due to residues (solid combustibles loss)
  - L_{df} = Dry flue gas loss
  - $L_{moist(f)}$ = Loss due to moisture and hydrogen in the fuel
  - $L_{moist(a)}$ = Loss due to moisture in air
  - L_{RC} = Loss due to radiation and convection
  - L_{co} = Loss due to unburnt CO in the flue gas
  - L_{shr} = Loss due to sensible heat of residues (bottom ash & fly ash)

- Loss due to combustibles (residues) — Lcomb

$$L_{Comb} = \frac{(\text{CV of C}) \times (\text{wt fraction of comb in ash}) \times (\text{wt fraction of ash in fuel})}{\text{HHV}} \times 100$$

Note: HH~~C~~V & CV of C to be taken in kJ/kg

- Dry flue gas loss — L_{df}

$$Ldf = \{\frac{100}{12 \times \%CO_2}\} \times \{C + \frac{S}{2.67} - U\} \times 30.6(tg - ta) \times 100 \div (HHV)$$

$\%CO_2$ = Percentage (volume) of CO_2 (dry basis) present in flue gases (dry basis) at the exit of the system

C = fraction of C content per unit mass of fuel

S = Fraction of S content per unit mass of fuel

U = Fraction of unburnt combustibles per unit mass of fuel

= (Wt. Fraction of combustibles in ash)× (wt fraction of ash in the fuel)

tg = Temperature of flue gas at the exit of the systems, °C

ta = Temperature of air at the entry of the system, °C

- Heat loss due to moisture & hydrogen in fuel, Lmoist(f)

  Total moisture in flue gas/kg of fuel

  $=(\%M + 9 \times \%H_2)/100$ kg/kg fuel

  where $\%M$ = wt% moisture in fuel

  $\%H_2$ = wt % hydrogen in fuel

- Heat/kg of moisture in flue gases

  $= 1.88(tg-25) + 2442 + 4.2(25-ta)$kJ/kg

Case A: For Solid and Liquid fuels

Heat less due to moisture in flue gas/kg of fuel

=(Total moisture in flue gas/kg of fuel) × (heat/kg of moisture in fuel gas) kJ/kg

Case B : For gaseous fuels

Heat loss due to moisture in flue gas/kg of fuel

$$= (9 \times \%H_2/100) \times (\text{Heat/kg of moisture in flue gases}) + \{\%M \times 1.88(t_g\text{-}t_a)\}$$

$\%H_2$ = percentage hydrogen in the fuel by wt

%M=percentage moisture in the fuel by wt

- Thus, heat loss due to moisture & hydrogen in fuel

$$\frac{\text{Heat loss due to mositure in flue gas/kg of fuel}}{\text{HHV}} \times 100$$

- Loss due to moisture in combustion air, Lmoist (a)

$$= A \times W \times 1.88\ (t_g\text{-}t_a)\ \text{kJ/kg}$$

where A=Mass of total dry air required for combustion, kg/kg of fuel fired

W=Water vapour content in air, kg/kg of dry air

- Loss due to CO in flue gas, Lco

$$\text{Lco} = \frac{(\text{wt\% of CO per unit mass of flue gas}) \times (\text{CV of CO})}{\text{HHV}}$$

CV of CO = 10,103 kJ/kg

- Loss due to sensible heat of residues, Lshr

$$\text{Lshr} = \frac{(\text{wt of bottom ash/kg of fuel}) \times (\text{Temp of bottom ash disharge - ambient temp.}) \times (\text{specific heat of bottom ash})}{\text{HHV}} \times 100$$

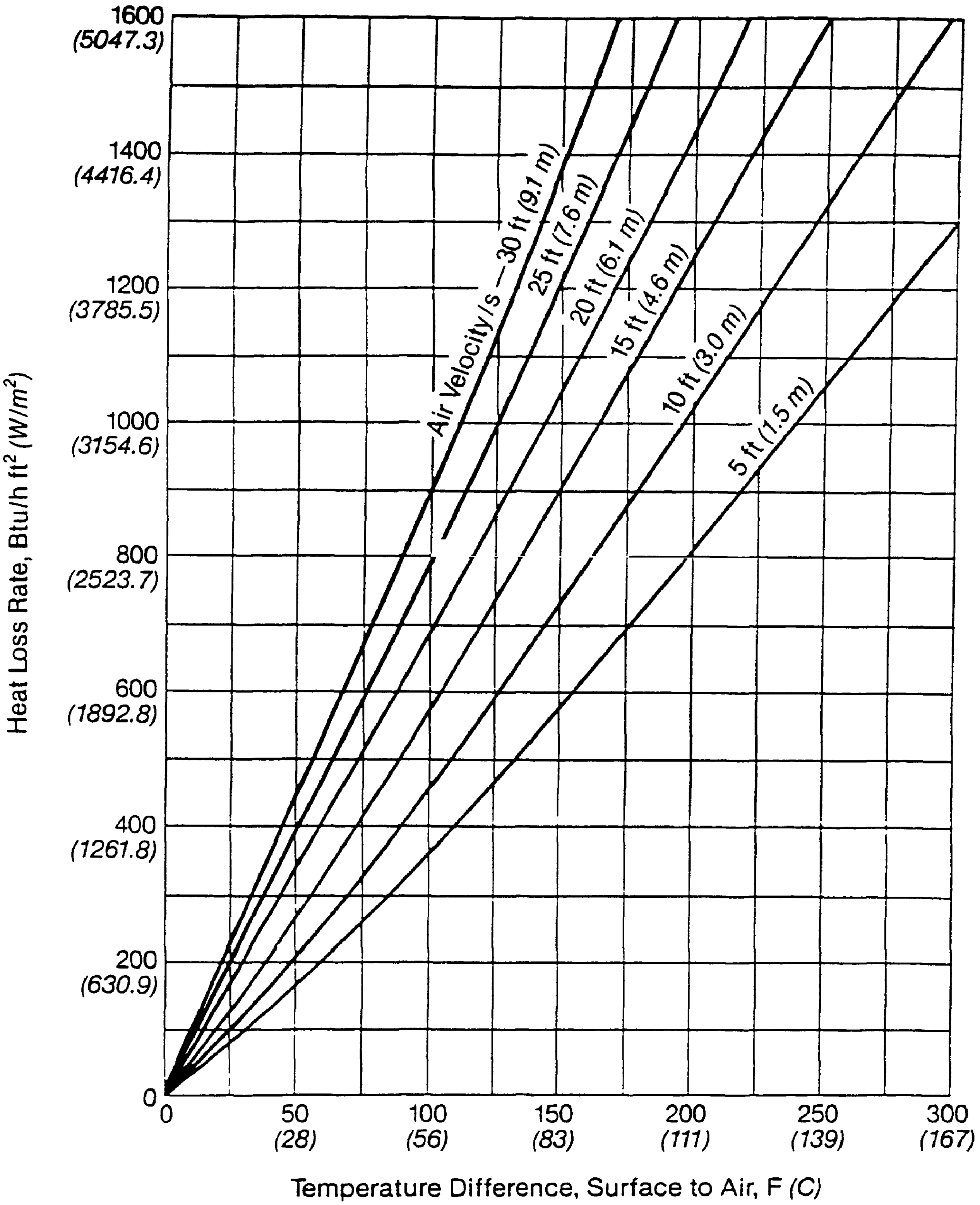
$$+ \frac{(\text{wt of fly ash/kg of fuel}) \times (\text{Temp of fly ash disharge - ambient temp.}) \times (\text{specific heat of fly ash})}{\text{HHV}} \times 100$$

For coal: Specific heat of bottom ash = 1.05 kJ/kg

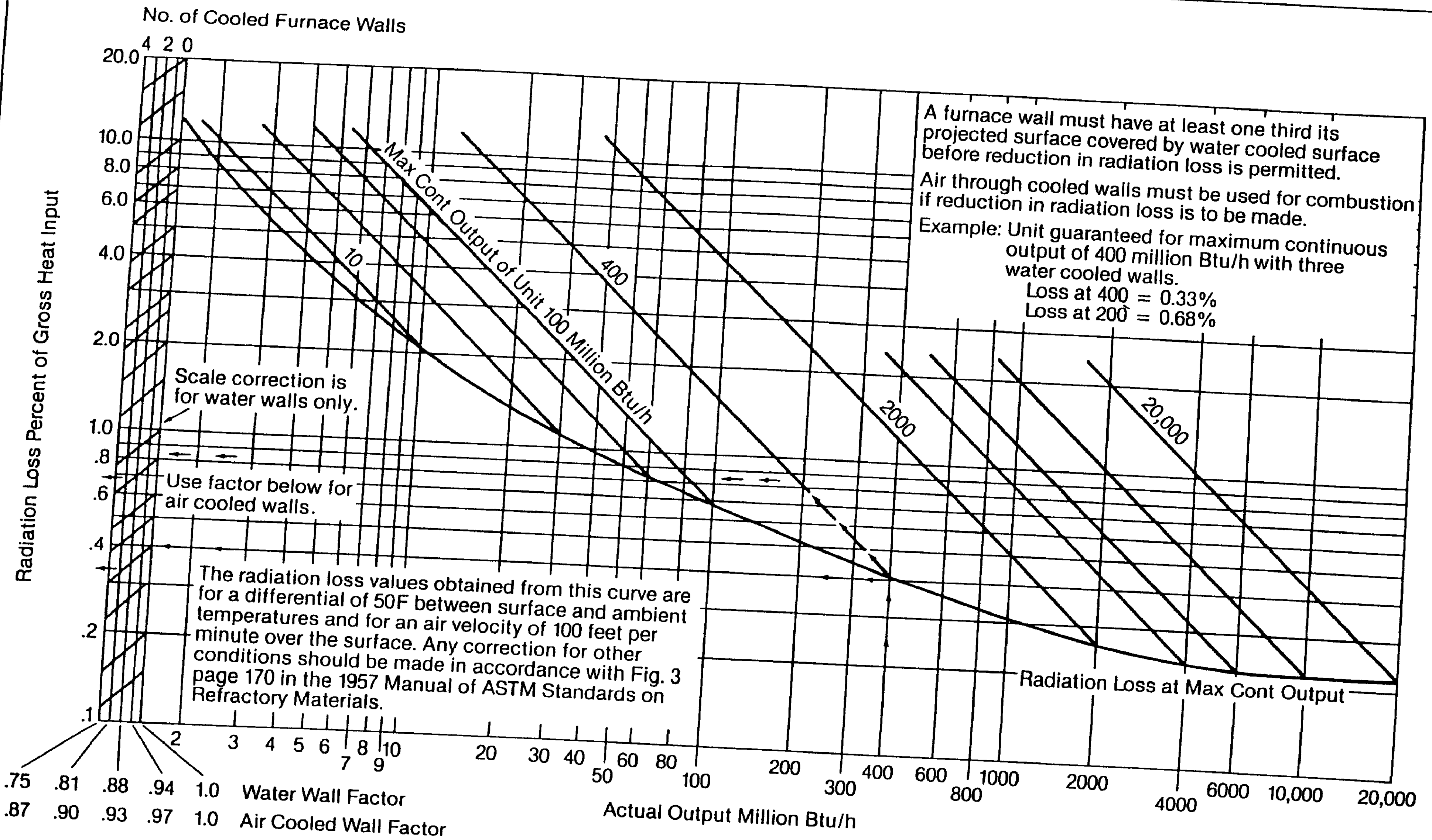
Specific heat of fly ash = 0.84 kJ/kg

- Loss due to radiation and convection

(Refer figures)



Heat loss from wall surfaces (radiation + convection). (Source — *ASTM Standards, Part 13,* 1969.)



A furnace wall must have at least one third its projected surface covered by water cooled surface before reduction in radiation loss is permitted.

Air through cooled walls must be used for combustion if reduction in radiation loss is to be made.

Example: Unit guaranteed for maximum continuous output of 400 million Btu/h with three water cooled walls.
Loss at 400 = 0.33%
Loss at 200 = 0.68%

Scale correction is for water walls only.

Use factor below for air cooled walls.

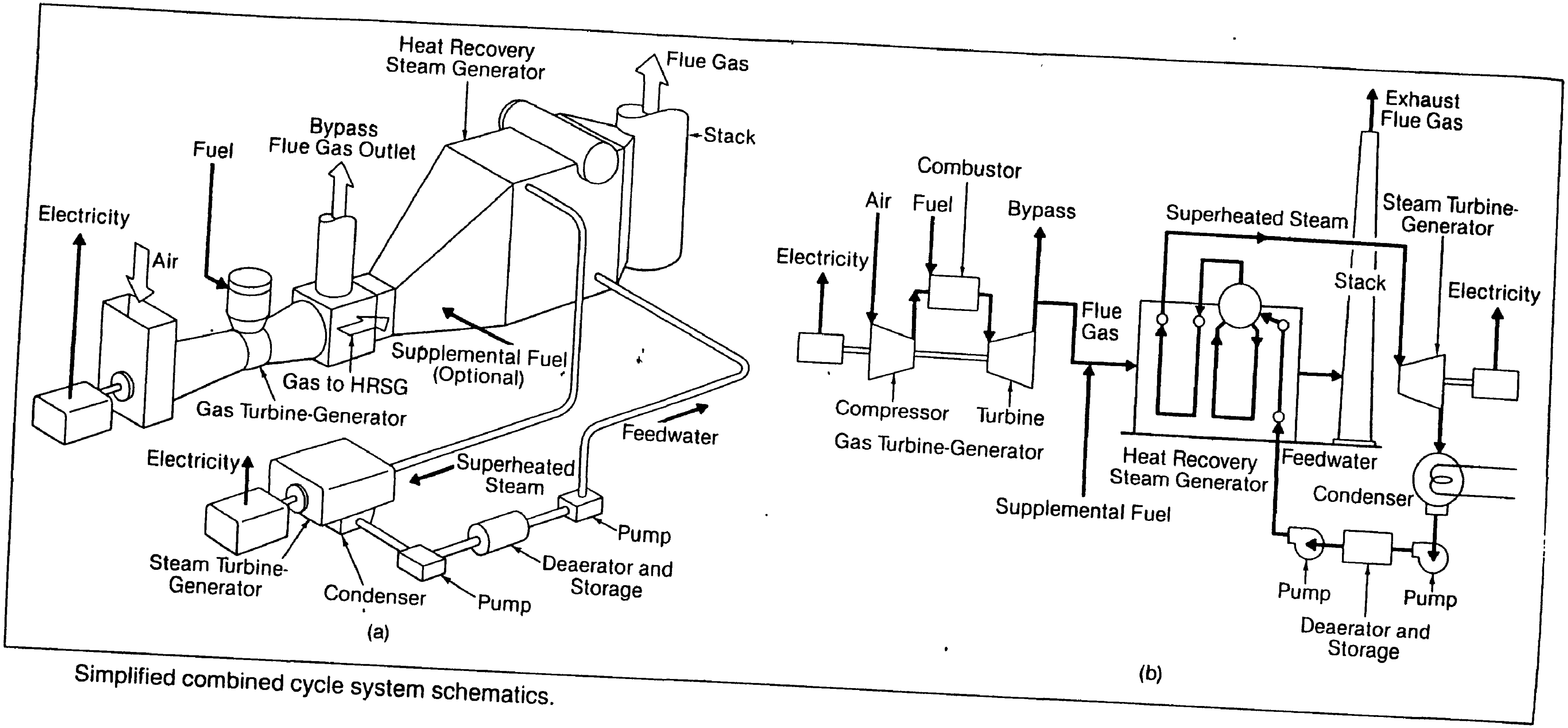
The radiation loss values obtained from this curve are for a differential of 50F between surface and ambient temperatures and for an air velocity of 100 feet per minute over the surface. Any correction for other conditions should be made in accordance with Fig. 3 page 170 in the 1957 Manual of ASTM Standards on Refractory Materials.

Radiation loss in percent of gross heat input (American Boiler Manufacturers Association).

Chapter 8

Heat Recovery Steam Generators

- Heat recovery for improving energy efficiency/economy
- Heat recovery for exhausts of
  - Gas turbines
  - Industrial furnaces/processes (e.g. steel, metal, refinery, petrochemicals, glass, food processing etc)
- Steam from HRSG used for
  - Rankine cycle power generation, or
  - Cogneration, or
  - Process heating
- Heat recovery through an economic solution
- Typical HRSG arrangement (refer figure enclosed)
- The range of gas temperatures from the exhausts of gas turbines and industrial furnaces/processes is given in the table (enclosed)
- Concept of combined cycle (refer figure enclosed). HRSG may be single pressure or multiple pressure, and with reheat as well. Two gas turbine exhausts may have a single HRSG and single steam turbine
- Combined cycles today can achieve efficiency around 60%
- Cogeneration: Steam from HRSG used for processes. Efficiency can approach 80%



Simplified combined cycle system schematics.

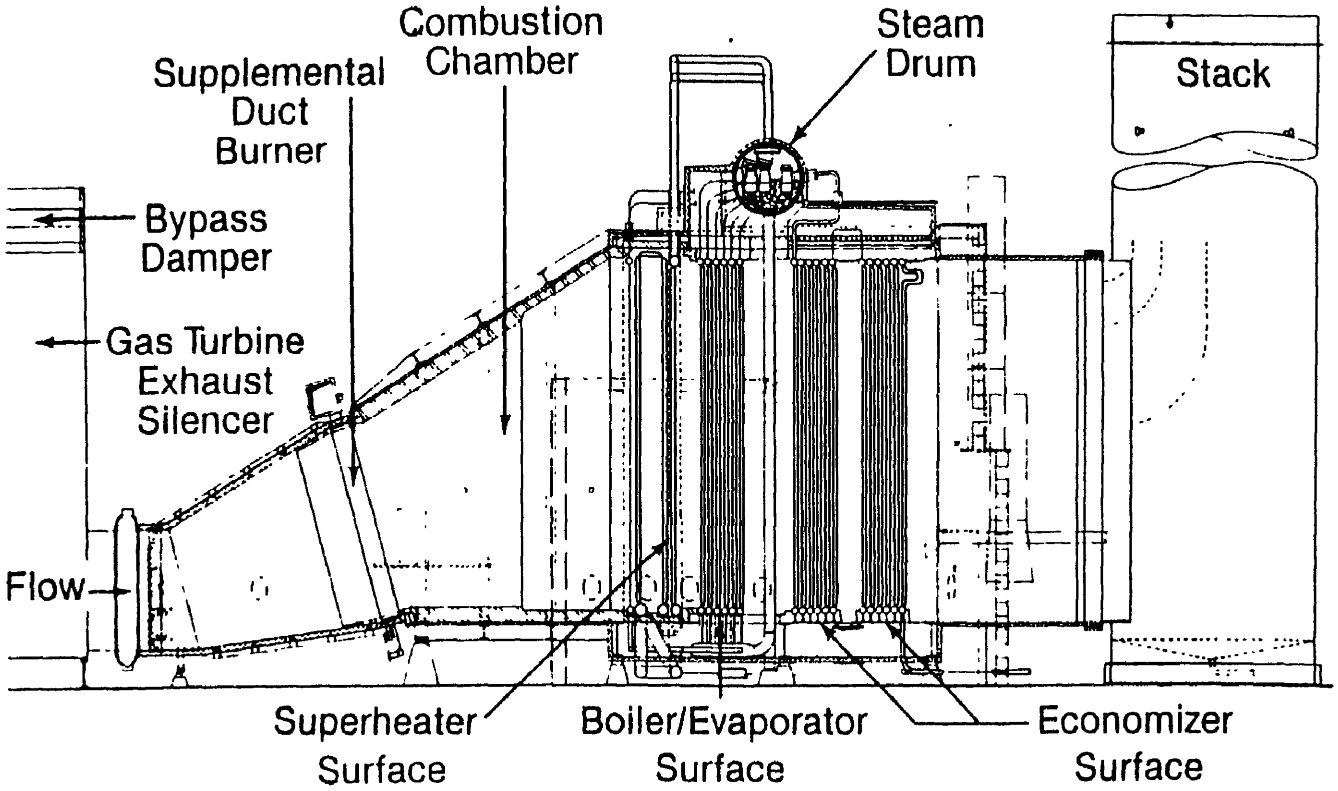
Sample Cycle Efficiencies and Heat Rates

System	Efficiency (%)	Heat Rate (Btu/kWh)
Simple gas turbine	32	10,700
Gas turbine plus unfired single pressure steam cycle	42	8,200
Advanced gas turbine plus unfired multiple pressure steam system	48	7,100
Gas turbine plus dual pressure steam system plus process steam use (cogeneration)	61	—

Note: All values are calculated using the higher heating value (HHV) of the fuel. Use of the lower heating value (LHV) of the fuel would increase the efficiencies listed.

HRSG

- Designed for specific applications
- Supplementary fuel firing possible through duct burners if the exhaust heat alone is not able to meet the steam conditions for specific application.
- Horizontal or Vertical design; correspondingly natural or forced circulation system
- Gas side pressure drop should be minimum; as the back pressure affects the gas turbine efficiency/output
- HRSGs are generally too large. Boiler cannot be shop assembled.So finned tube bundles made as modules as per fabrication shop limitation and ease of transportation and erection.
- Technical considerations for design
  - Allowable back-pressure
  - Steam pressure and temperature
  - Pinch point
  - Super heater & economiser approach temperatures
  - Stack outlet temperature (limited by gas Dew point)



Heat recovery steam generator (HRSG) arrangement.

HRSG Parameters

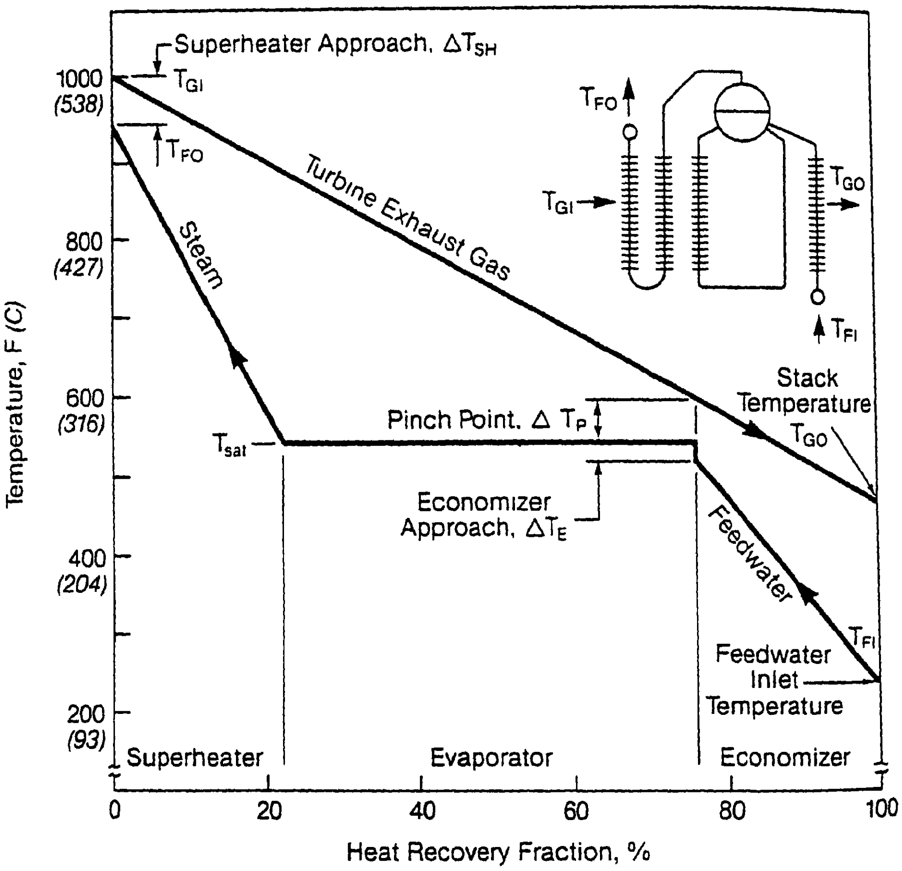
Turbine application:	
Gas turbine sizes	1 MW to 220 MW
Gas flow	25,000 to 5,000,000 lb/h (0.32 to 630 kg/s)
Gas turbine outlet temperature	≤ 1200F (≤ 649C)
Supplemental firing temperature	≤ 1650F (≤ 899C)
Steam flow:	15,000 to 600,000 lb/h (1.9 to 76 kg/s)
Operating pressures:	
High	≥ 400 psig (28 bar gauge)
Intermediate	50 to 400 psig (3.4 to 28 bar gauge)
Low	15 to 50 psig (1.03 to 3.4 bar gauge)
Steam temperature	up to 1005F (541C)
Supplemental fuels	#2 oil, natural gas

- Back pressure is typically 10 to 15 in wg in most units
- Pinch point and approach points (refer figure attached) have significant impact on the overall size of the unit. Smaller values for pinch point and SH approach point result in larger heat transfer surfaces, and thus, higher capital cost.
- Economiser approach point is set to avoid steaming of economiser
- Following ranges provide economical and technically feasible design:

  Pinch Point, ΔT_p = 20 to 50°F (11 to 28°C)

  Superheater approach, ΔT_{SH} = 40 to 60°F (22 to 33°C)

  Economiser approach, ΔT_E = 10 to 30°F (6 to 17°C)



Temperature profile in single pressure HRSG.

Contd.

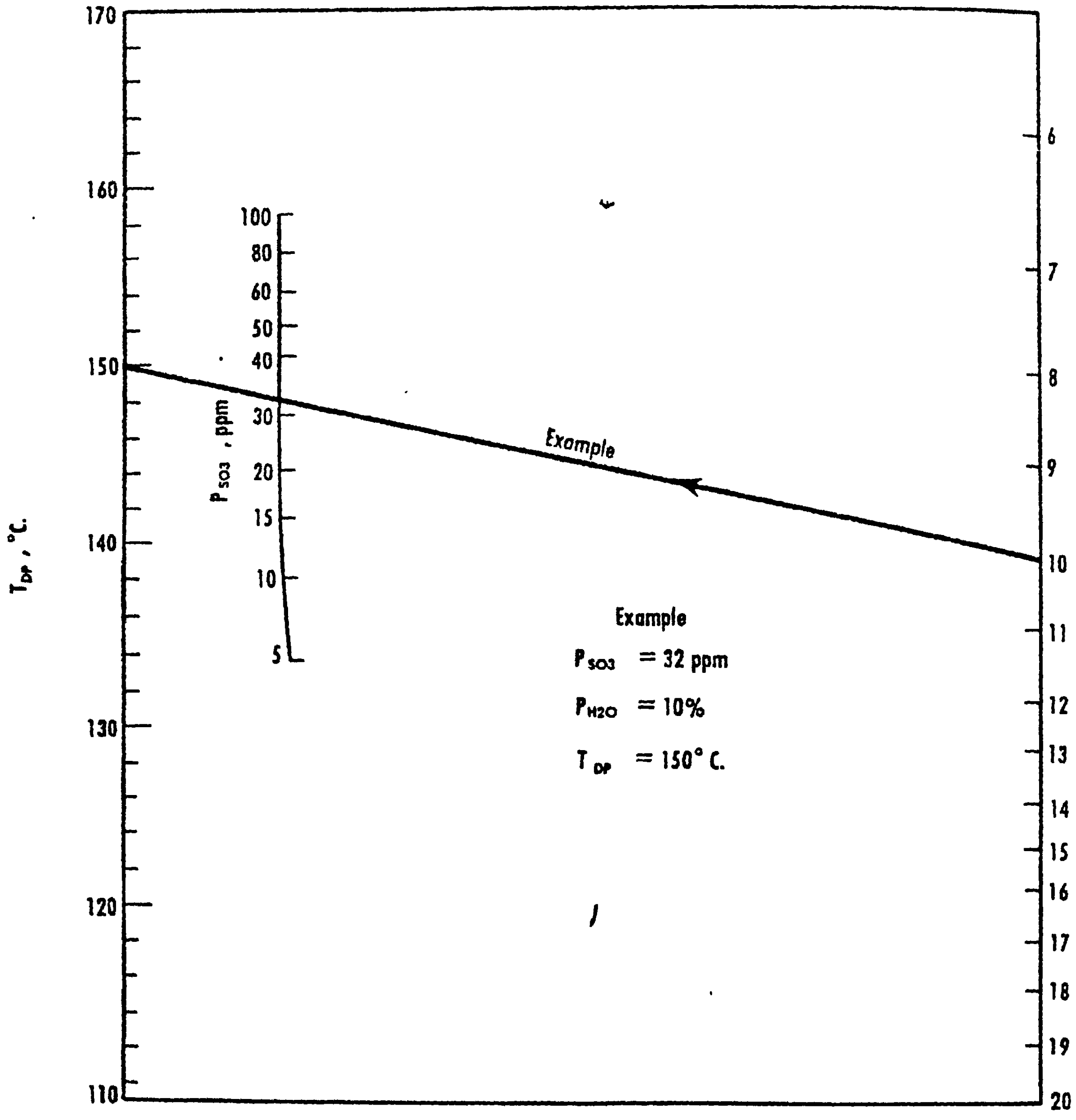
- Minimum feedwater temperature is set based on the dew point of the gas, to avoid corrosion. If S is present in the fuel, feedwater temperature is typically 240°C.
- To avoid acid concentration, the exit gas temperature should be selected in such a way that metal temperature is above recommended minimum metal temperature (refer enclosed figure)
- Steam pressure and temperature selected for economical design (multiple pressure outputs may be designed for most economical design)
- If economiser is steaming, (1) final section of economiser to the drum should be up-flow, (2) re-circulation line during start-up, (3) economiser discharge above the drum level in the steam-water separation section.

Heat recovery from waste gases

- Heat absorbed depends up temperature, thermo-physical properties of gases, velocity, direction of flow, and surface cleanliness.
- Temperature of waste gases at different industry is different (given in the enclosed table)
- Suitable draft (through ID fan or chimney) must be provided to overcome pressure drop in HRSG
- Heat transfer is by convection only. Gas side velocities are high. Recommended velocities given in (A) and (B) of enclosed figure.
- Water cooled vestibule is also used in many HRSGs, to prevent slagging over the tube bundles. Velocities employed for vestibule section are as recommended in (C) of the figure.
- If hot gases carry dust, higher tube spaces are provided. Soot blowers may be required. Sometimes manual cleaning with compressed air or steam or water. Hoppers provided to collect dust.

Temperature of Waste Heat Gases

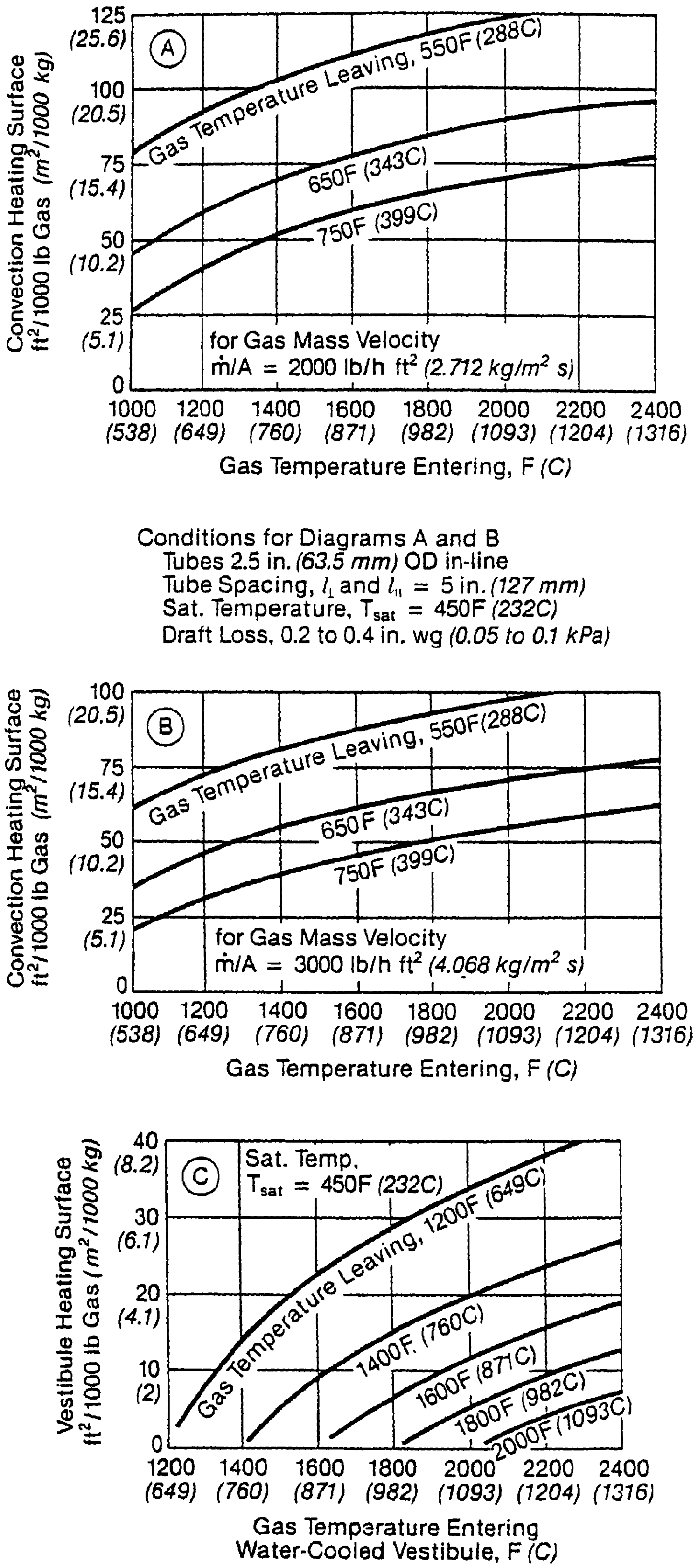
Source of Gas	Temperature F	C
Ammonia oxidation process	1350 to 1475	732 to 802
Annealing furnace	1100 to 2000	593 to 1093
Cement kiln (dry process)	1150 to 1500	621 to 816
Cement kiln (wet process)	800 to 1100	427 to 593
Copper reverberatory furnace	2000 to 2500	1093 to 1371
Diesel engine exhaust	1000 to 1200	538 to 649
Forge and billet heating furnaces	1700 to 2200	927 to 1204
Open hearth steel furnace, air blown	1000 to 1300	538 to 704
Open hearth steel furnace, oxygen blown	1300 to 2100	704 to 1149
Basic oxygen furnace	3000 to 3500	1649 to 1927
Petroleum refinery	1000 to 1400	538 to 760
Sulfur ore processing	1600 to 1900	871 to 1038



T_{DP} , °C.
170
160
150
140
130
120
110
P_{SO3} , ppm
100
80
60
50
40
30
20
15
10
5
Example
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
Example
P_{SO3} = 32 ppm
P_{H2O} = 10%
T_{DP} = 150° C.

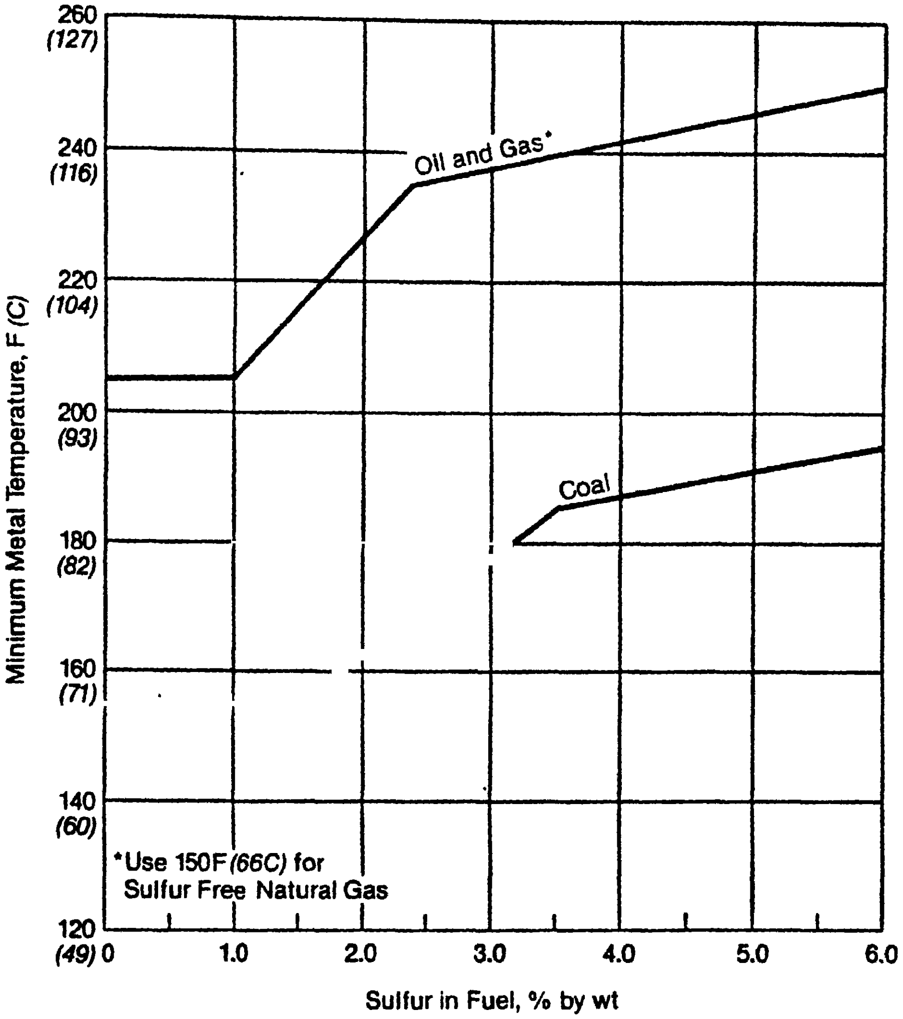
Table 1. SO_3 in Flue Gas

Fuel	Excess air, %	Sulfur, % 0.5	1.0	2.0	3.0	4.0	5.0
		SO_3, ppm					
Oil	5	2	3	3	4	5	6
	11	6	7	8	10	12	14
Coal	25	3-7	7-14	14-28	20-40	27-54	33-66



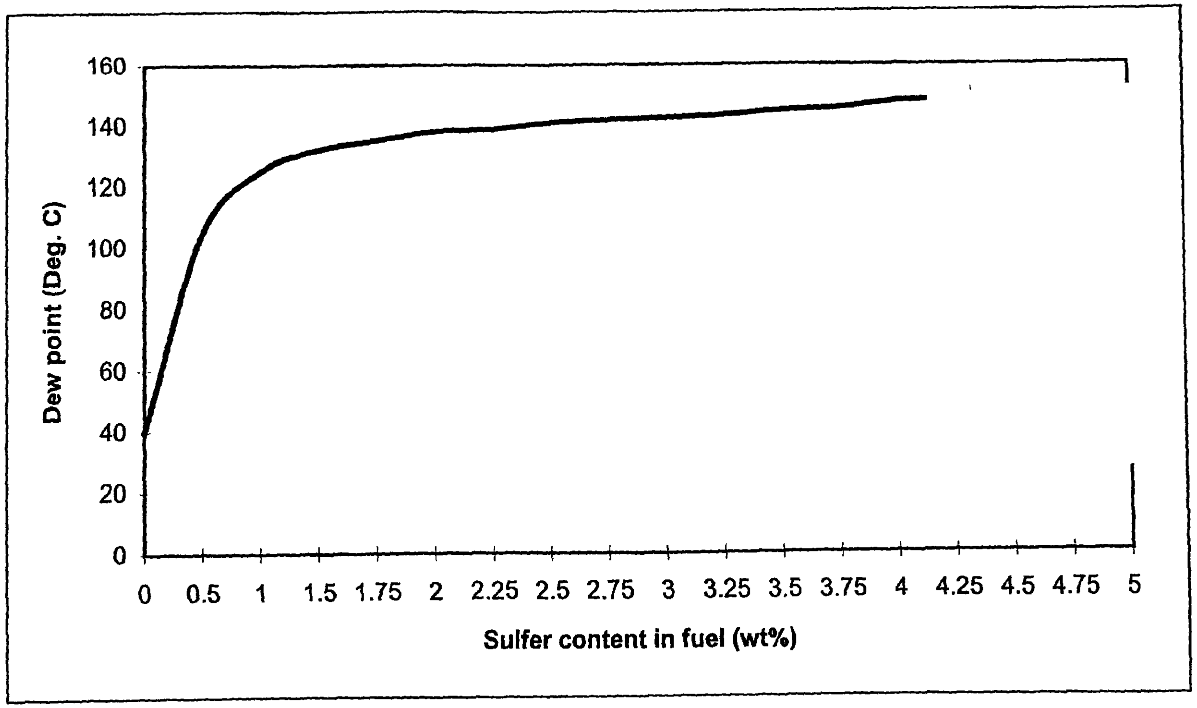
Conditions for Diagrams A and B
Tubes 2.5 in. *(63.5 mm)* OD in-line
Tube Spacing, $l_{\perp}$ and $l_{\parallel}$ = 5 in. *(127 mm)*
Sat. Temperature, T_{sat} = 450F *(232C)*
Draft Loss, 0.2 to 0.4 in. wg *(0.05 to 0.1 kPa)*

Approximate surface required in convection tube bank and vestibule for various entering and leaving waste gas temperatures.

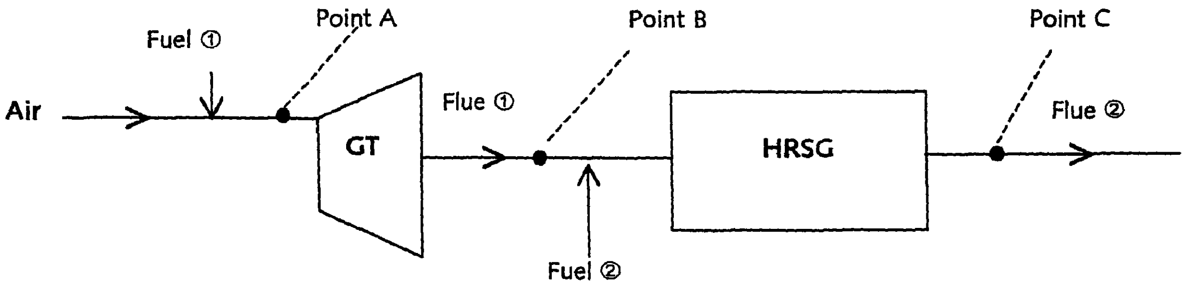


Regenerative air heater cold end MMT limits when burning sulfur bearing fuels.

Sulfer content in fuel (wt %)	Dewpoint temperature (oC)
0	40
0.5	105
1	125
1.5	132
1.75	135
2	137.9
2.25	138.6
2.5	140.8
2.75	141.6
3	142.3
3.25	143
3.5	144.5
3.75	145.3
4	147.5
4.25	148
4.5	148.9
4.75	149.7
5	151.2



Energy efficiency testing of HRSG



Data required

- Fuel 1 composition (wt% C, H, N, S, O)
- HCV of Fuel 1 (kCal/kg)
- Feed rate of Fuel 1 (kg/h)
- Feed temperature of Fuel 1 (°C)
- Specific heat of fuel 1 (kCal/kg°C)

- Composition of Flue ① (Vol%, CO_2, O_2, SO_2, N_2)
- Temperature of Flue ① (°C)
- Composition of Fuel ② (wt% of C, H , N, S, O)
- HCV of Fuel ② (kCal/kg)
- Feed temperature of Fuel ② (°C)
- Specific heat Fuel ② (kCal/kg°C)

- Composition of Flue ② (Vol% Co_2, O_2, SO_2, N_2)
- Temperature of Flue ② (°C)

HRSG steam parameters (p, temperature, flow rate)
Ambient temperature
Wet Bulb temp/RH

Losses for HRSG (expressed as % of heat input)

- Dry flue gas loss
- Loss due to moisture in Flue ② /(Inlet air)
- Loss due to hydrogen in Fuel ① & Fuel ②
- Radiation loss

HRSG efficiency = 100 – (sum of above losses)

Methodology

- Stoichiometric (carbon) balance between Point A & Point B to calculate
  - Rate of Flue 1 (m_1, kg/h)
  - Heat in the flue 1 [$q_1 = m_1 \times C_p \times$ Temperature of Flue 1]
  - Heat input to HRSG [$q_1 +$ (Feed rate of fuel 2 × C_p of fuel × temp of fuel]
  - Amount of air fed to GT
  - Amount of moisture in air to GT & thus heat losses due t moisture in Flue 2
- Stoichiometric (nitrogen) balance Point B & Point C, to calculate
  - Rate dry flue (dry)
  - Heat in flue ②
  - Rate of fuel ② feed raten
  - Hydrogen from fuels ① & ② and thus losses due to hydrogen